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| Witness: | Michael L. Brosch |
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| Sponsoring Party: | State of Missouri |
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**BEFORE THE PUBLIC SERVICE COMMISSION**

**STATE OF MISSOURI**

# DIRECT TESTIMONY

# OF

# MICHAEL L. BROSCH

# ON BEHALF OF

# STATE OF MISSOURI

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## TABLE OF CONTENTS

## DIRECT TESTIMONY OF MICHAEL L. BROSCH



**Attachments**

**BEFORE THE PUBLIC SERVICE COMMISSION**
**OF THE STATE OF MISSOURI**
**DIRECT TESTIMONY OF MICHAEL L. BROSCH**
**ON BEHALF OF THE STATE OF MISSOURI**
**CASE NO. ER-2007-0002**

Q. Please state your name and business address.

A. My name is Michael L. Brosch. My business address is 740 North Blue Parkway, Suite 204, Lee's Summit, Missouri 64086.

Q. What is your present occupation?

A. I am a principal in the firm Utilitech, Inc., a consulting firm engaged primarily in utility rate and regulation work. The firm's business and my responsibilities are related to special services work for utility regulatory clients. These services include rate case reviews, cost of service analyses, jurisdictional and class cost allocations, financial studies, rate design analyses and focused investigations related to utility operations and ratemaking issues.

Q. On whose behalf are you appearing in this proceeding?

A. I am appearing on behalf of the State of Missouri ("State"). Utilitech entered into a contract with the State of Missouri to review and address the rate case revenue requirement of Union Electric Company d/b/a Ameren UE ("UE", "AmerenUE" or "Company").

Q. Please summarize the purpose and content of your testimony.

A. My testimony explains certain issues associated with the AmerenUE revenue requirement and I sponsor several ratemaking adjustments to the test year that are necessary to establish just and reasonable rates. I address the need for a customer growth annualization adjustment to test year sales and revenue margins, as well as adjustments required to normalize and annualize fuel and purchased power costs and off-system sales margins. I also sponsor several adjustments addressing production operations and maintenance ("O&M") expenses, emission allowances and depreciation issues arising from anticipated remaining useful lives for nuclear and coal-fired steam generating facilities. My testimony also addresses ratemaking treatment for the Electric Energy, Inc. affiliate, valuation adjustments for purchased generating assets from corporate affiliates and adjustments required to test year income tax expenses. The individual ratemaking adjustments I sponsor have been incorporated into the <u>State Joint Accounting Schedules</u>, which are explained in additional detail within the testimony of State witness Mr. Steven C. Carver.

## EDUCATION AND EXPERIENCE

Q. What is your educational background?

A. Schedule MLB-1 is a summary of my education and professional qualifications.

Q. Please summarize your professional experience in the field of utility regulation.

A. My professional experience began in 1978, when I was employed by the Missouri PSC as part of the accounting department audit staff. While with the Staff from 1978 to 1981, I participated in rate cases involving Kansas City Power and Light Company, Missouri

Public Service Company, Southwestern Bell and several smaller Missouri utilities. Since leaving the Commission Staff, I worked as an independent consultant and have testified before utility regulatory agencies in Arizona, Arkansas, California, Florida, Hawaii, Illinois, Indiana, Iowa, Kansas, Michigan, Missouri, New Mexico, Ohio, Oklahoma, Utah, Washington, and Wisconsin in regulatory proceedings involving electric, gas, telephone, water, sewer, transit, and steam utilities. I have participated in many electric, gas and telephone utility regulatory proceedings, as listed and described in Schedule MLB-2.

## EXECUTIVE SUMMARY

Q. Please summarize your Direct Testimony.

A. My testimony describes several ratemaking adjustments that should be recognized in determining the Company's revenue requirement. First, I sponsor an adjustment to account for continuing growth in the number of customers served by the Company, through December 2006, which causes revenue growth that is available to help "pay for" increasing expenses. Second, I recommend updating of the input assumptions used to calculate test year fuel expense, purchased power and off-system sales, utilizing more current information from calendar 2006 in place of estimated amounts employed by AmerenUE. Third, I recommend imputation of excess earnings being achieved by the Company's EE Inc. affiliate as a result of management's removal of Joppa Plant capacity from jurisdictional operations. Each of these adjustments involves preliminary or incomplete data and is subject to revision and updating as part of the true-up in this Case.

I sponsor several other ratemaking adjustments to correct the Company's filing for omissions or improper accounting proposals within the filing, including adjustments for the Taum Sauk outage costs, accounting for a new Labadie Plant ash disposal arrangement, recognition of a new Internal Revenue Code deduction, rejection of increased depreciation accruals arising from unsupported generating unit retirement assumptions, recognition of gains realized by UE upon sale of emission allowances, valuation adjustments for generating asset purchased from an affiliate at excessive prices and elimination of retroactive amortization being proposed by AmerenUE for Osage Plant headwater benefit charges. Each of the adjustments I sponsor are set forth in the <u>State Joint Accounting Schedules</u> that are discussed in the Direct Testimony of State witness Mr. Steven Carver. An Index appears in front of the State Joint Accounting Schedules that identifies the State witness sponsoring each of the individual schedules therein.

## CUSTOMER GROWTH

Q. Please describe State Adjustment/Schedule C-1.

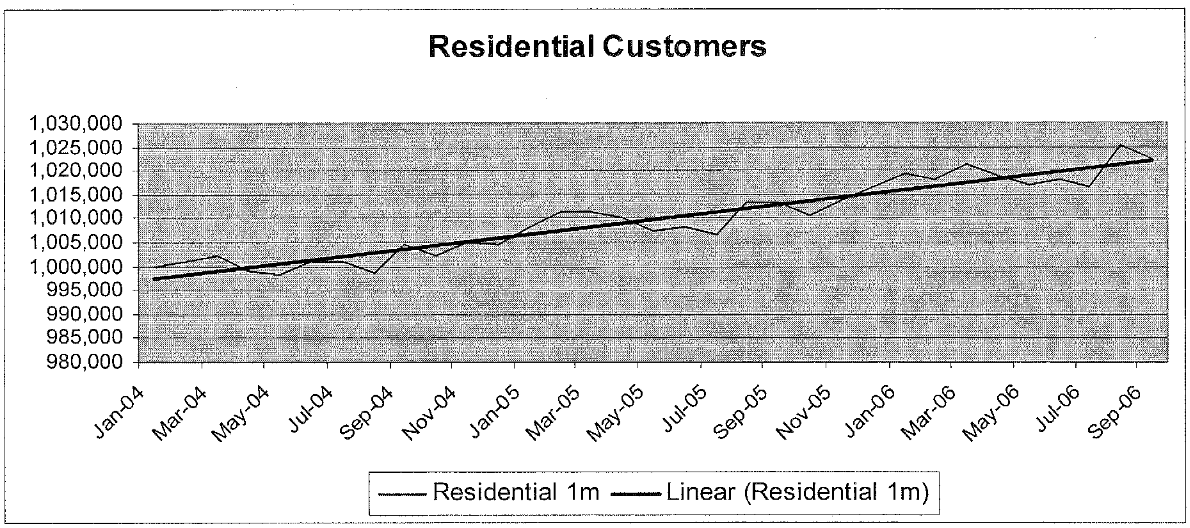
A. Adjustment C-1 serves to increase test year revenues to account for estimated customer growth through year-end 2006.

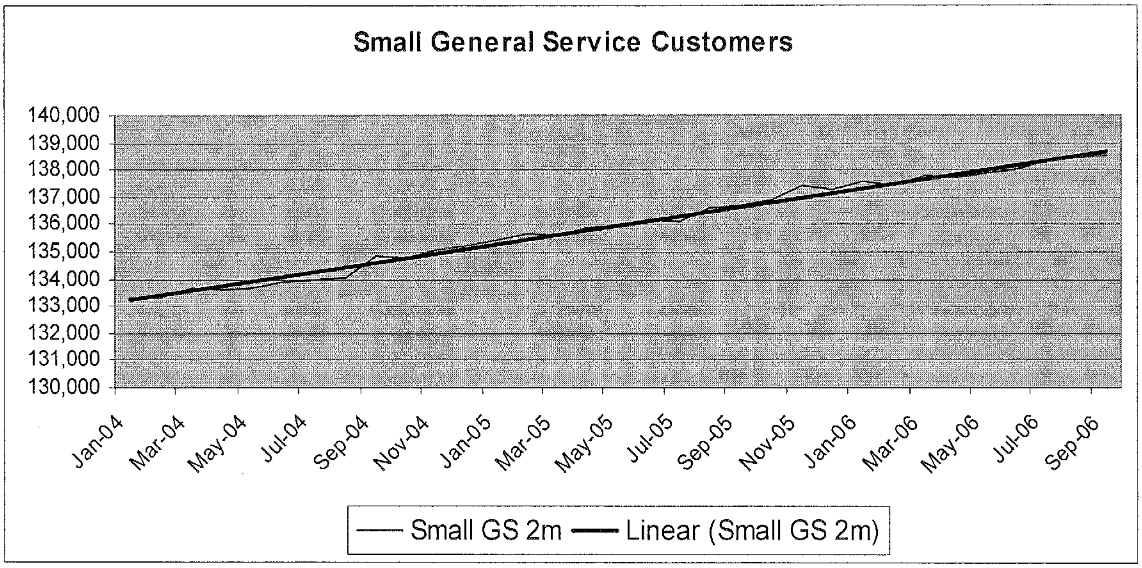
Q. Why is it important to recognize growth in the number of customers served by an electric utility such as UE?

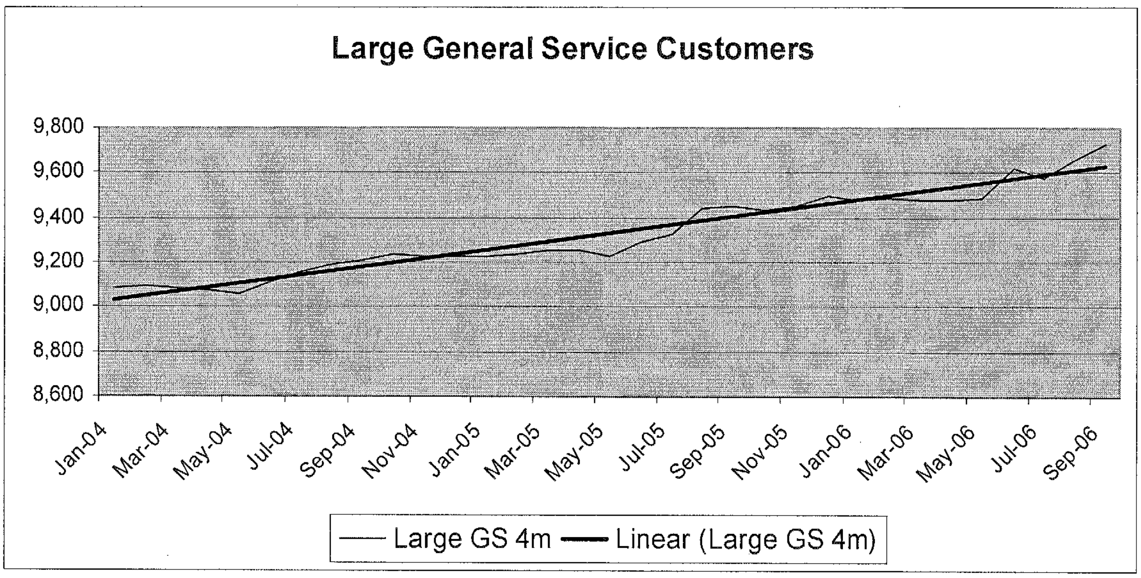
A. Changes in the number of customers served by the utility will have a direct impact upon sales volumes and revenue margin levels (revenues less energy costs). A growing utility that is adding new customers is typically able to offset much of the growth in its rate base and operating expenses with new revenues earned by serving new customers. If changes in costs are annualized at the end of the test year or beyond, as UE proposes in this case, it is important to fully account for changes in customer and sales levels to the same point in time to properly match elements of the revenue requirement. Mr. Carver discusses the test year in this case and the need to properly match the cutoff of rate base, revenues and expenses in an internally consistent or "matched" manner so as to not overstate or understate the revenue requirement.

Q. Has Ameren UE been experiencing persistent growth in the number of residential and small commercial electric customers that are served?

A. Yes. According to the Company's response to Data Request AG/UTI-84, the number of customers served by UE has increased steadily since January of 2004. The following graphs indicate actual monthly customer counts for the Residential, Small General Service and Large General Service customer classes:






These graphs illustrate the monthly fluctuations around a generally increasing trend line associated with the number of customers being served by UE.

Q. What approach is employed in the State Adjustment for estimated customer growth?

A. The trend information shown in these graphs reflect actual data through September 2006. I have extended the linear trend lines to December 2006 to calculate an adjustment that should serve as a place holder at this time, to be replaced by true-up calculations using actual customer data as of December 31, 2006 when such data becomes available. Using a linear trending approach to project the December customer counts at this time should have the effect of smoothing any fluctuations in the historical data. State Adjustment Schedule C-1 shows the actual calculations that are employed, based upon the derivation of a "Customer Growth Factor" value for each major customer class, which is the ratio of projected December 31 customers to average actual customer counts during the test period. This growth percentage is applied to the normalized test year revenues and MWH sales for each customer class, as shown at UE witness Mr. Pozzo's Schedule JRP-E8, to derive an estimate of the additional revenue and sales that UE will realize as a result of customer growth through the end of 2006.

Q. How did you quantify the "Estimated Fuel/Energy Cost for Customer Growth" at line 10 of the Adjustment Schedule?

A. This amount is explained in footnote 1 as the average per MWH energy cost rate included in the Company's filing according to the response to Data Request No. AG/UTI-202, as revised for the State's estimated test year fuel expense adjustments described later in my testimony.

Q. Do you object to a true-up calculation to update the customer annualization for actual customer statistics as of December 31, 2006 or to update the related fuel and purchased power costs involved in serving additional customers at that date?

A. No. Actual customer count data as of December 31, that is consistent with the information provided in UE's response to Data Request AG/UTI-84, can be substituted for the estimated December customer count data in the Adjustment, recalculating the growth factor percentage ratio. Similarly, if the Commission revises the weather normalized test year revenue or MWH values sponsored by Mr. Pozzo, as shown at lines 4 and 5 of the Adjustment, the revised normalized sales and revenue values should be employed. The estimated fuel and purchased power costs should be tied to the energy costs ultimately approved by the Commission for energy costs in base rates, against which any future fuel adjustment clause calculations will be applied.

## OFF-SYSTEM SALES MARGINS

Q. Please describe Adjustment/Schedule C-2.

A. Adjustment C-2 updates the Company's estimated test year off-system sales margins, based upon average market energy prices experienced by the Company in 2006, through the month of September 2006. This adjustment is provisional and should be updated to consider additional actual monthly 2006 off-system sales pricing data for the last quarter of 2006 as part of the true-up revisions to the revenue requirement.

Q. What are off-system sales and why are they included in determining the AmerenUE revenue requirement?

A. The Company engages in interchange sales transactions of electricity when it has available generating capacity beyond what is required to serve AmerenUE native loads and when that capacity can economically meet market demands for bulk energy. Because such off-system sales of electricity are made utilizing jurisdictional generating facilities, it is appropriate that a reasonable estimate of the ongoing level of profit margins on such sales (revenues less incurred energy costs) be credited to ratepayers.

Q. How did the Company determine its proposed off-system sales prices and volumes for the test year?

A. UE witness Mr. Schukar explains the process used by the Company to develop estimated test year off-system sales volumes, revenues and margins. His approach relies upon average monthly historical pricing data from the calendar years 2003, 2004 and 2005, with adjustments intended to normalize for abnormalities in such data.[1] Mr. Schukar provided market energy price estimates to UE witness Mr. Finnell for inclusion in the Company's ProSym model, so as to simulate operation of the generating fleet to meet native loads along with market opportunities to make off-system sales. The result of this estimation effort is an estimated $183.5 million level of off-system sales margins that is sponsored by AmerenUE witness Schukar for the test period.[2]

Q. What is the source of the average market price data used to establish your recommended level of off-system sales margins?

A. Rather than relying upon historical 2003-2005 market energy prices, I relied upon actual Midwest Independent System Operator ("MISO") hourly average price data for each of the months January through September 2006, as supplied by AmerenUE in its response to Data Request Staff 269. These prices are somewhat higher than the 3-year historical

[1] Direct Testimony of Shawn E. Schukar, pages 8-12.
[2] Supplemental Direct Testimony of Shawn E. Schukar, page 2, line 8.

average adjusted off-system sales prices from the years 2003 through 2005 that were employed by AmerenUE witness Schukar. When additional MISO pricing information becomes available for the last quarter of 2006, additional updating should be performed using this data source.

Q. Why is it important to update off-system sales prices to reflect more current market price data in 2006?

A. AmerenUE, like other electric utilities in the Midwest, has experienced generally increasing fuel prices. This increasing fuel cost environment appears to be contributing to increasing market prices for energy. This trend is embedded within the annual price data used by Mr. Schukar to develop his 3-year average of market energy prices:

** confidential table [redacted] **

When evaluating expense levels, not surprisingly, the Company has proposed to include its latest known and measurable fuel costs within calculated revenue requirements, rather than a three year average of prior years' costs. For example, AmerenUE has proposed inclusion of its estimated January 2007 contract prices for coal fuel supply[3]. This makes it important and appropriate, in my opinion, to also include the most current available off-system sales energy prices for off-peak energy to maintain fuel cost/energy price comparability.

[3] Direct Testimony of Timothy D. Finnell, page 8, line 17.

Q. What source data has been used in the State's adjustment to estimate more current market energy prices for the purpose of updating off-system sales estimated margins?

A. I propose using monthly average MISO energy prices and have incorporated the first nine months of available data for calendar 2006 in the provisional adjustment that I sponsor. This adjustment should ultimately be updated with more current actual data as part of the true-up calculations performed early in 2007. In comparison to the price data in the table above, the average weekday peak price for year-to-date September 2006 has been $56.56 and the corresponding off-peak price has averaged $25.51, continuing the trend in recent years toward generally higher prices.

Q. Why did you utilize hourly MISO price information for this purpose?

A. AmerenUE is a member of MISO, which coordinates the dispatch of its system and the provisioning of off-system sales in the region. According to the Direct Testimony of AmerenUE witness Mr. Birk, each AmerenUE generating unit is bid into the MISO market on a day ahead or real time basis where the AmerenUE generating units are provided with opportunities to sell available energy into the MISO market.[4] Therefore, MISO defines the market for short term power sales. AmerenUE confirmed in its response to Data Request AG/UTI-150 that hourly MISO Day Ahead market energy prices that were provided in its response to Data Request No. Staff 269 are comparable to the input data utilized by Mr. Schukar to estimated normalized energy pricing based upon his earlier 2003-2005 analysis period.

[4] Direct Testimony of Mark C. Birk, page 14.

Q. What is the source of the megawatthour sales volume data that is used to establish your recommended level of off-system sales margins?

A. I have accepted for purposes of my adjustment the estimated off-system sales volumes estimated by the Company using its ProSym dispatch simulation program, as sponsored by AmerenUE witness Mr. Finnell. Adjustment/Schedule C-2 sets forth a comparison of off-system sales levels I recommend, relative to the Company's proposed off-system sales revenue levels, to derive the ratemaking adjustment required to embed the State's recommended off-system sales margin level into the Company's revenue requirement.

Q. Earlier you mentioned that AmerenUE employed updated January 2007 contract coal prices in determining test year fuel expense. Were 2007 prices also used by the Company for its gas and oil price inputs used in calculating fuel expenses?

A. No. The Company intended to also employ a three-year average of historical 2003, 2004 and 2005 gas and oil prices, with adjustments for abnormalities in such data. However, the Company erroneously failed to post its intended adjustment to normalize for Katrina hurricane effects upon gas fuel dispatch prices.[5] This resulted in inappropriate gas and oil prices being included by the Company in its ProSym model. As noted in my testimony regarding fuel prices, below, I have updated AmerenUE's gas and oil fuel prices to reflect average 2006 fuel price levels, so as to maintain comparability of peaking generation fuel prices to the corresponding market energy prices that have been updated in my adjustment to reflect 2006 levels.

[5] Response to Data Request No. AG/UTI-79, part d.

Q. Do you believe that off-system sales margins should be subject to regulatory tracking and adjustment, either as part of the Company's fuel adjustment clause tariff that is sponsored by Company witness Mr. Lyons, or through a separate deferred accounting tracking mechanism if the Commission does not approve an FAC for the Company?

A. Yes. For any given electric utility, off-system sales market prices and the resulting profit margins can vary significantly from one month to the next, depending upon a number of variables such as weather, generating unit availability, ongoing growth in demand and capacity reserve levels. Beyond this "normal" level of variability, AmerenUE is experiencing several fundamental changes in its ability to make off-system sales, arising from termination of the EE Inc. purchased power contract, the planned termination of the Joint Dispatch Agreement, and the addition of substantial new combustion turbine peaking capacity.[6] These fundamental changes cause historical AmerenUE off-system sales experience to be of little value in predicting future sales margins for the Company at this time. For these reasons, AmerenUE off-system sales are quite difficult to reliably estimate for ratemaking purposes at this time. The Company has estimated future off-system sales that may occur in this changed environment using ProSym simulation calculations with inputs revised to estimate the effect of these fundamental changes, but there is no historical benchmark against which the resulting off-system sales estimates can be evaluated.

Q. Has Mr. Schukar acknowledged the increased uncertainties surrounding estimation of off-system sales for AmerenUE at this time?

[6] These and other considerations are listed as "known changes" that Mr. Schukar identified at page 6 of his Direct Testimony as directly affecting off-system sales margins.

A. Yes. In Section V. of his Direct Testimony, Mr. Schukar describes the "Uncertainties associated with off-system sales margins" and discusses a sharing mechanism that might be employed to track changes in off-system sales margins that occur in the future, relative to the amounts built into base rates.

Q. Should there be any sharing of off-system sales margins, as suggested by Mr. Schukar, if such margins are subject to rate tracking?

A. No. There has been no showing by the Company that its shareholders bear any costs or risks associated with the generating facilities or other resources involved in making off-system sales. With ratepayers supporting the costs that make such sales possible, ratepayers should receive <u>all</u> of the margins that are realized. Moreover, it cannot be denied that management has a responsibility to its customers to diligently work toward reducing the net cost of providing regulated electric utility services, which includes an obligation to optimize off-system sales opportunities. Any disincentive for management to optimize AmerenUE off-system sales that is believed to be caused by rate tracking of margins can be mitigated by detailed reporting of sales performance, periodic regulatory auditing of off-system sales results and comparisons of UE bulk energy sales performance to transactions made by Ameren on behalf of its other non-regulated business units.

Q. Has this Commission previously rejected claims by Missouri electric utilities that shareholders should be allowed to retain a share of off-system sales margins?

A. Yes. In Missouri Public Service Division of Utilicorp United Inc., Case No. ER-97-394, the Commission rejected that utility's proposal that shareholders be allowed to share off-system sales margins on a 50/50 basis, stating, "The Commission finds the Staff provided competent and substantial evidence that all of the off-system sales revenue should be reflected in the test year revenue for the purposes of setting rates. The Staff is correct in stating that, since all of the costs of producing the off-system sales revenue were borne by the ratepayers, and since UtiliCorp has benefited from regulatory lag, the total amount of this revenue should be included in rates." More recently, in the regulatory plan approved by the Commission for Kansas City Power & Light Company, the parties have stipulated that ratepayers are entitled to 100 percent of margins earned by KCPL from engaging in off-system sales.[7]

## FUEL AND PURCHASED POWER EXPENSE

Q. Please describe Adjustment/Schedule C-3.

A. Adjustment C-3 annualizes test year fuel expenses, based upon average 2006 year-to-date gas and oil prices and a revised estimate of AmerenUE delivered coal prices effective January 2007. These adjustments would be subject to true-up calculations when more complete actual data becomes known. Such amounts would also be subject to future fuel adjustment clause tracking, if the Commission approves AmerenUE's proposed fuel adjustment clause ("FAC") tariff.[8]

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[7] In re Kansas City Power & Light, Case No. EO-2005-0329; Mo PSC Report and Order (July 28, 2005), page 18.

[8] The State's response to AmerenUE's proposed Fuel Adjustment Clause will be set forth in testimony to be separately filed on December 29, 2006.

Q. What approach was taken to calculate estimated fuel and purchased power expenses for the test year in the State's adjustment that you sponsor?

A. Utilitech did not conduct any independent fuel expense simulation calculations. Therefore, I have accepted as reasonable the Company's pro-forma dispatch of its generating units to meet test year adjusted loads. The adjustment I propose merely re-prices the fuel input values to reflect updated estimated delivered coal, gas and oil fuel unit prices. No adjustments are proposed to the nuclear fuel prices used by AmerenUE for estimated normalized test year utilization of the Callaway unit. These adjustments are placeholders for amounts that are expected to be trued-up to known and measurable actual levels as of January 2007.

Q. What is the source of the estimated January 2007 estimated coal prices you have included in your calculations?

A. I relied primarily upon AmerenUE's revised response to Staff Data Request No. 310, which supplied updated contract Powder River Basin ("PRB") and Illinois coal price projections and freight contract pricing estimates as a starting point to derive estimated January 2007 prices. I then made several revisions to the Company's calculations in this data request, as follows:

- Revision of the projected fuel blend at Meramec Station, to reflect ** [redacted] ** in accordance with the AmerenUE response to Staff Data Request No. 309.

- Elimination of estimated costs for ** [redacted] ** as speculative expenses that are not known and measurable at this time, based upon the responses to Staff Data Request Nos. 307, 308 and 310.[9]

- Utilization of ** [redacted],** per AmerenUE's response to Staff Data Request 301D.

- Eliminate of ** [redacted] ** according to AmerenUE's response to Staff Data Request No. 310D.

- Inclusion of rail freight diesel surcharges assuming diesel fuel index prices of $2.70 per gallon, based upon year-to-date 2006 average diesel fuel prices.

After these revisions, I applied the resulting estimated delivered coal fuel cost per MMBTU values to the Company's estimated dispatch simulation of coal-fired generation output. The resulting adjustment appears at line 1 of Adjustment C-3.

Q. What information was used to calculate the gas and oil price adjustment at line 2 of Adjustment C-3?

A. Actual average monthly natural gas and oil prices, as experienced by AmerenUE at each station in the months of January through September 2006 were employed. These amounts are included as the best available indication of ongoing natural gas and oil prices that the Company is currently paying in the period of time coinciding with the updated off-system sales prices used to calculate State Adjustment C-2.

Q. What information was used to calculate the purchased power input price adjustment at line 3 of Adjustment Schedule C-3?

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[9] If magnesium hydroxide costs are included as part of fuel expenses, upon completion of operational and economic analysis of this fuel additive, it would be necessary to study and quantify O&M and fuel cost savings resulting from use of the additive, as outlined in AmerenUE's response to Data Request No. MPSC 307.1

A. Actual average monthly MISO market energy prices, as experienced by AmerenUE at each station in the months of January through September 2006 were employed. These amounts are included as the best available indication of ongoing market short term purchased energy prices that the Company is currently paying.

Q. Do you object to updating of the coal, gas, oil and purchased power prices you have adjusted as part of a true-up calculation for the test year?

A. No. The Commission should seek to include the latest available known and measurable fuel and market energy prices that are representative of ongoing conditions when setting the Company's base rates and to establish a base cost of energy for administration of any FAC that may be established in this Case.

## ELECTRIC ENERGY INC. – JOPPA STATION

Q. Please describe Adjustment/Schedule C-4.

A. Adjustment C-4 imputes an annual revenue credit into the AmerenUE revenue requirement calculation to return the economic value of the Joppa plant to regulation, to the benefit of Missouri ratepayers.

Q. What is the Joppa Station and how has it been treated historically by the Commission?

A. The Joppa Station is a large coal-fired generating facility near Joppa, Illinois that was constructed by UE and other sponsoring utilities and placed into service in the mid 1950's to serve the power requirements of the United States Atomic Energy Commission ("AEC"), with the sponsoring utilities taking and paying for any excess energy beyond the requirements of the AEC. The Company has taken and paid for unit power from Joppa since the plant was constructed and commenced operations starting in 1954. Purchased power expenses incurred by UE for the Company's share of power produced at Joppa have been considered as part of the Company's operating expenses for many years.

Q. Was the Joppa Station owned or constructed directly by UE and the other sponsoring utilities?

A. No. A new entity, Electric Energy, Inc., was formed by the sponsoring utilities to own and operate the plant and to engage in cost-based power sales arrangements with AEC and among themselves. In MPSC Case No. 12,064, UE requested and received Commission authorization to acquire 40 percent of the issued shares of capital stock of the new Electric Energy, Inc. entity and this 40 percent ownership interest has been held by UE since that date. As a result of mergers with Central Illinois Public Service Company and Illinois Power Company, Ameren has consolidated its holdings of EE Inc. so that today Ameren Energy Resources Company ("AER") owns a second 40 percent interest, with Kentucky Utilities holding the remaining 20 percent ownership interest; which is the only part of EE Inc. not controlled by Ameren Corporation.

EE Inc. has historically contracted for the sale of all output from the Joppa Station at cost-based prices, either to the federal government or to the sponsoring companies. The most recent cost-based Power Sale Agreement among UE and the other sponsoring companies was for a term starting in 1987 and ending December 31, 2005. Through such cost-based power sales arrangements, EE Inc. was able to shift essentially all of the operating risks and costs associated with the Joppa Station to its sponsoring utilities.

Q. Did UE historically include its share of purchased power expenses arising from the various EE Inc. power sales agreement obligations in determining its Missouri jurisdictional revenue requirements?

A. Yes. I am aware of no ratemaking adjustments made in prior UE rate cases to disallow any purchased power expenses arising from the EE Inc. power sales agreements.

Q. Has EE Inc. historically recovered all of its costs incurred at Joppa Station through its power sales to AEC and the sponsoring utilities, including UE?

A. Yes. According to the UE response to Data Request No. AG/UTI-28, the Company is not aware of any year in which EE Inc. experienced any operating losses while UE ratepayers were paying cost-based contract prices for the UE share of output from the Joppa Station.

Q. What is the significance of past ratemaking treatment for energy produced by Joppa Station that was purchased by UE?

A. By including EE Inc. cost-based charges to UE within recorded purchased power expenses in rate cases, UE ratepayers have provided funding for EE Inc. operating expenses as well as a reasonable return on and return of EE Inc.'s investment in the Joppa Station for many years, in proportion to UE's ownership interest and capacity commitment in the Station. This result is analogous to including the UE 40 percent share of Joppa investment in rate base and in operating expenses, while treating energy sales to the federal government as revenue credits (since such sales were also cost-based).

Q. Does it matter, from the perspective of Missouri ratepayers, that UE did not directly own a share of the Joppa Station, but instead the costs incurred at Joppa to provide capacity and energy to UE were recovered through long term purchased power arrangements?

A. No. It is of little consequence that EE Inc.'s capital investment in plant was not made directly by UE, since all costs including a return on investment appear to have been recovered from ratepayers with the same end result as if UE's interest investment in the Joppa Station were jurisdictional to UE.

Q. Aside from the financial support to EE Inc. provided through a long history of cost-based power sales agreements, has UE provided any financial guarantees to assist EE Inc. in securing debt financing?

A. Yes. When UE's initial investment in EE Inc. was reviewed and approved by the Commission in 1950 in Case No. 12,064, the Company's Application dated February 8, 1950 explained the equity investment to be made by UE as well as repayment assurances made for the benefit of debt investors in the Joppa Plant:

> It is expected that the facilities of Electric Energy, Inc. will cost approximately $65,000,000. The funds for providing such facilities are expected to be raised by the borrowing by Electric Energy, Inc. of 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. The loans to be made by institutional investors have been agreed to in principle, and the detailed terms and provisions are in the course of negotiation. In order further to assure the repayment of such loans the Companies would agree to be responsible for the use or sale of the capacity of such generating facilities, in case the

> AEC 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., which would make Petitioner responsible for 40% of such capacity.

By this arrangement, UE appears to have committed its ratepayers to take and pay for the UE share of any Joppa Plant capacity output not purchased by the AEC. The Commission approved UE's Application in Case No. 12,064 to acquire its 40% interest in EE Inc. without hearing by its Order dated December 8, 1950.

In 1977, in Case No. EF-77-197, the Commission approved certain additional financing arrangements proposed by UE for the benefit of EE Inc. stating, "The Commission held that authority to "guaranty" certain financial obligations of EEInc through the execution, delivery and performance of the second amendment to Amended Intercompany Agreement is in the public interest and should be granted." (21 Mo.P.S.C.(N.S.) at 425).

Q. Does the Joppa Plant, under EE Inc. ownership, continue to benefit from its affiliation with AmerenUE?

A. Yes. Through an ** [redacted].[10] **

[10] Response to Data Request No. AG/UTI-210.

Q. Would it be reasonable, in your opinion, to consider AmerenUE's investment in EE Inc. to be a regulatory asset?

A. Yes, although not in the traditional accounting definition of this term. Regulatory assets generally represent costs incurred by the utility for which future rate recovery is assured by the regulatory agency. In this instance, there is no tangible expenditure that has been made by UE or EE Inc. that represents the current market value of the Joppa Station or the market value of station output. Instead, the market value of this asset is the result of constructing, operating and maintaining, largely at ratepayer risk and expense, an established asset that has appreciated in market value and that produces a valuable income stream at today's energy prices. Even though the UE interest in EE Inc. was held as a non-regulated asset on the balance sheet and governed by a separate Board of Directors, the underlying business operations of the Joppa Station have been treated as jurisdictional before this Commission for many years. Absent a showing by the Company that its shareholders have borne significant risks and costs arising from such operations outside of regulation, there is no basis today to treat UE's 40 percent share of EE Inc., and the corresponding market value and income stream, as anything but a regulatory asset.

Q. When the latest cost-based supply agreement between EE Inc. and UE expired on December 31, 2005, what was the financial impact upon UE?

A. The cost-based supply agreement that was effective prior to 2006 provided a stable and nearly risk free return to EE Inc., which UE recognized as below-the-line income for its shareholdings on its 40 percent ownership interest in EE Inc. The UE regulated utility business recognized purchased power expense and corresponding utility sales revenues reflecting cost recovery for such expense. UE was able to use the low cost purchased power to serve its native load or to engage in profitable off-system sales.

Immediately in 2006, when the cost-based supply agreements with sponsoring companies terminated, EE Inc. began selling energy at much higher market-based prices, recording sharply increased revenues and earnings. On its below-the-line investment in the 40 percent ownership interest in EE Inc., windfall profits are now being recorded that Ameren intends to retain for its shareholders. In contrast, the UE regulated utility business is now forced to replace the EE Inc. energy it had purchased for many years at attractively low, cost-based prices with much higher current market-priced energy, and to forego the opportunity to make profitable off-system sales supplied by Joppa cost-based energy. By allowing the historical cost-based supply contracts to expire, Ameren management was able to shift the market value of UE's 40 percent stake in the Joppa Station from UE ratepayers to its shareholders, by moving the income stream created by the Station to its nonregulated accounts.

Q. Is management obligated in any way to continue the historical arrangement for sale of the Joppa Station output at cost-based prices after December 31, 2005, even though the 1987 Power Supply Agreement had expired on that date?

A. I am not an attorney and cannot offer any legal opinion regarding the obligations of management. Ultimately, this may be a question for the Commission to decide. However, I believe that equity and fairness dictates a regulatory outcome in which ratepayers who shouldered the costs and risks associated with the UE share of Joppa for many prior decades through their rates should not be denied continuing participation in the current market value of energy output of the Station. Moreover, there is no justification from a risk/return perspective in allowing Ameren management, acting through their controlling position on the EE Inc. Board of Directors, to achieve windfall below-the-line profits from Joppa Station by electing to not extend the historical Power Supply Agreement. Notably, the ratemaking adjustment I propose does not require the Commission to compel any extension of the expired Power Supply Agreement, but rather would impute the windfall profits now being recorded by the UE subsidiary resulting from such termination into the ratemaking calculations of UE as a revenue credit.

Q. What is the basis for your claim that "windfall" profits have been achieved by EE Inc. upon termination of the cost-based Power Supply Agreement at December 31, 2005?

A. The following graph depicts EE Inc. reported MWH sales and revenues before and after termination of the cost-based Power Supply Agreement:

**** confidential graph

Confidential graph ****

The dramatic increase in monthly EE Inc. revenues, with relatively little change in monthly sales volumes, is an indication of the value that Ameren seeks to transfer below the line if it is allowed to retain the market value of Joppa output for shareholders.

When viewed on a per MWH basis, the financial result of the Company's proposal is even more dramatic:

**** confidential graph

**** confidential graph

With no significant change in output from the Joppa Station, EE Inc. has been able to dramatically increase its revenue per MWH of sales. Since expenses have not materially changed, the substantial revenue increase at EE Inc. translates into massive increases in reported net income per MWH.

Q. Have you examined EE Inc.'s return on equity for the period before and after expiration of the cost-based Power Supply Agreements?

A. Yes. Monthly average return on equity for the first nine months of 2005 was *** [redacted]***, which is reflective of cost-based contract pricing under the Power Supply Agreement that was effective. After this Agreement terminated and EE Inc. began charging higher market prices, its average return on equity for the first nine months of 2006 was *** [redacted]***. This increase has occurred with no significant change in plant investment levels or operations at Joppa and cannot be attributed to management actions for which any economic windfall should be retained as a reward or incentive. Unless corrected by the Commission, UE will be allowed to extract the market value of Joppa output for the sole benefit of its shareholders, with a corresponding increase in UE revenue requirements that is not justified by management action or inaction.

Q. Please explain how you calculated the EE Inc. revenue imputation adjustment that is set forth in confidential Adjustment Schedule C-4.

A. The adjustment starts with the ** [redacted] **

Q. Why is the adjustment you propose based upon only nine months of accounting data for EE Inc.?

A. On January 1, 2006, EE Inc. commenced sales of the Joppa Plant output at market prices, rather than selling at the cost-based prices required under previously effective power sales agreements. At the time this testimony was prepared, only the first nine months of accounting data for EE Inc. had been provided in response to the State's discovery. I would not object to an update of this adjustment to reflect more current full year information when available.

Q. Is it reasonable to expect that EE Inc. revenues will fluctuate as market prices of energy change?

A. Yes. The output of EE Inc. that is now being sold at market prices is similar to the challenge of estimating and fixing the revenues and margins for UE's own off-system sales. Market prices fluctuate and 2006 average prices may not be the best proxy for future market conditions. Therefore, if the Commission determines it reasonable to "track" changes in off-system sales for UE, a comparable tracking calculations should be performed for the UE share of excess profits earned by EE Inc., using the methodology presented in the State's Adjustment Schedule C-4.

Q. Are you aware of prior instances where this Commission has imputed revenues associated with excess earnings of a utility affiliate when the affiliate's income stream arises from operations conducted jointly with the utility?

A. Yes. One analog is the Commission's past imputation of excess earnings recorded by the directory publishing affiliates of regulated local exchange telephone companies in Missouri. Directory publishing is a highly profitable business segment undertaken by the large telephone holding companies which are able to sell advertising in the yellow pages by virtue of their established relationship with telephone subscribers and the public perception that their directories are more "official" and valuable than competitive books. Even though Southwestern Bell (now again AT&T) and GTE Telephone (now Verizon) conduct their directory publishing business outside of the regulated entity, in the era of traditional rate of return ratemaking for the telephone companies the excess profits of the publishing affiliates were routinely imputed into utility operations to reduce the revenue requirement.[11]

## TAUM SAUK EXPENSES

Q. Please describe Adjustment/Schedule C-5.

A. This adjustment removes $10 million of accrued expenses that were included in the Company's rate filing in connection with the Taum Sauk incident. AmerenUE should not be allowed to recover such costs from its ratepayers because they are not normal ongoing and prudently incurred costs associated with providing utility services. In response to Data Request No. AG/UTI-89, the Company stated, "Adjustment #9 on Schedule GSW-E-29-1 attached to the Supplemental Direct Testimony of AmerenUE witness Gary S. Weiss should be increased by the $10,000,000." In addition, Adjustment C-5 reflects, at lines 3 through 8, a further reduction for wage costs charged to the Taum Sauk outage project by Ameren Services employees which could have been allocated to entities other than AmerenUE if the Taum Sauk event had not occurred.

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[11] In re Southwestern Bell TC-93-224, TO-93-192; 2 MPSC 3d 479, 519 (Dec. 17, 1993)
In re Southwestern Bell TC-89-14, TC-89-21, TO-89-29, TO-89-10 consolidated; 29 MoPSC (NS) 607, 640 (June 20-1989).
In re GTE North TR-89-182, TR-89-238, TC-90-75 consolidated; 30 MoPSC (NS) 88, 104 (Feb. 9, 1990)

Q. Would the Taum Sauk outage complicate implementation and administration of any fuel adjustment clause that is under consideration for AmerenUE at this time?

A. Yes. Any future FAC rate adjustments that are based upon changes in per book actual fuel and purchased power costs incurred by the Company will be impacted by the higher costs incurred because of the Taum Sauk outage. This could force ratepayers to pay for the higher incurred fuel costs and purchased power costs caused by the Taum Sauk incident. While the test year ProSym calculations underlying the Company's test year fuel cost estimates have been prepared as if Taum Sauk is fully available,[12] the reality is that per book fuel and purchase power expenses will continue to be higher because of the outage. In its response to Data Request AG/UTI-83, the Company stated that test year estimated fuel expense and purchased power expense would be $6.4 million higher if Taum Sauk were modeled as unavailable for the entire year. There is also a negative impact upon realized off-system sales margins caused by the Taum Sauk outage, which AmerenUE estimates to be about $15 million annually in the same Data Request response.

Q. Do the Commission's fuel adjustment rules preclude recovery of increased costs resulting from negligent or wrongful acts or omissions by the utility?

[12] Direct Testimony of Timothy D. Finnell, page 8, line 11.

A. Yes.[13] If an FAC is approved for AmerenUE, it would be necessary to carefully monitor and adjust recorded costs to ensure that ratepayers are not charged for Taum Sauk outage effects.[14]

Q. What could be done to insure that ratepayers do not pay through any AmerenUE fuel adjustment calculations for any adverse operational impacts arising from the Taum Sauk outage?

A. Two alternatives may be considered to "shield" ratepayers from the loss of the Taum Sauk facility. One approach would be to calculate the base cost of energy in this Case as if Taum Sauk were <u>not</u> available, so that future comparisons to actual fuel costs do not result in excessive FAC recoveries due to the higher per books expenses that are caused by the outage. Alternatively, one might require special studies in the future to estimate the impact of the Taum Sauk outage upon recorded actual fuel costs so as to adjust such costs downward prior to calculating the FAC rate. Under either approach, if off-system sales margins are also being tracked, correcting adjustments would be needed to account for estimated amounts of such margins that are lost due to unavailability of Taum Sauk.

## <u>ASH DISPOSAL EXPENSES</u>

Q. Please describe Adjustment/Schedule C-6.

A. According to a September 20, 2006 Press Release issued by the Company, a new concrete packaging facility opened at the Labadie Station on that date for the purpose of

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13 4 CSR 240-20.090 (1) Definitions states that "Fuel and purchased power costs means prudently incurred and used fuel and purchased power costs, including transportation costs. Prudently incurred costs do not include any increased costs resulting form negligent or wrongful acts or omissions by the utility."

14 The State intends to address AmerenUE's proposed Fuel Adjustment Clause in separately filed testimony to be submitted on December 29.

recycling more than 60,000 tons of fly and bottom ash annually into two million bags of high-qualify concrete mix. This ratemaking adjustment is to include an estimated $924,000 annual ongoing savings expected to be achieved by AmerenUE at the Labadie generating station as a result of this recent arrangement with Charah, Inc., under which Charah will operate a process facility to bag approximately 66,000 tons per year of Labadie ash for resale through retailers as concrete mix. AmerenUE expects to be able to avoid future ash disposal costs of about $14 per ton under the terms of this arrangement.

Q. Is any initial investment or start-up cost expected to be incurred by UE under the new arrangement?

A. Yes. According to the "Pakmix Business Plan" dated October 25, 2005 that was provided in response to Data Request AG/UTI-014, "This plan calls for Ameren to invest $3.3 million in a bagging plant facility at Labadie Plant for the benefit of Charah, Inc. to package and distribute to Home Depot Stores in the St. Louis area various bagged concrete products." Offsetting these up front costs is the statement, "Proceeding with the project will allow utilization of approximately 175,000 additional tons of bottom ash for site development, yielding an avoided ash disposal expense of $2,450,000 immediately." Thus, it appears that the net up-front cost is less than $1 million when these "immediate" savings are realized starting in October of 2005. At an annual savings rate of $924,000 per year, all of any remaining up-front costs should be more than fully offset by ongoing ash disposal savings before new rates from this rate case proceeding are implemented by the Company.

## OSAGE HEADWATER BENEFITS EXPENSES

Q. Please describe Adjustment/Schedule C-7.

A. Adjustment C-7 corrects the AmerenUE ratemaking adjustment proposed by Mr. Weiss for Osage Plant Headwater Benefits charges that are assessed by the FERC based upon the energy production benefits received by UE as a result of United States Corps of Engineers operation of six federal headwater storage projects within the Osage River Basin.[15]

Q. Why does the Company's ratemaking adjustment require correction?

A. The Company's adjustment has three parts. One part of the adjustment reflects the increased ongoing annual headwater benefit expense that was ordered by the FERC, increasing test year expenses from $275,335 to $409,731. This part of the adjustment is reasonable and is supported by the FERC Order which resets the ongoing assessments at $409,731 per year starting in 2005.

The second part of the Company's adjustment eliminates a $6.5 million expense accrual booked in April of 2006, during the test year, to reflect the estimated costs that may be owed in connection with the headwater study matter. This accrual was later reversed when the actual final assessments from FERC became known. Elimination of this accrual is also reasonable, since UE's normal ongoing expenses do not include large one-time FERC assessments for headwater benefits that should become part of the Company's revenue requirement.

[15] In its response to Data Request AG/UTI-60, UE provided copies of the FERC Order issued September 25, 2006 that adopted a revised Headwater Benefit Study and finalized assessments to UE; 116FERC¶62,228.

The third part of the Company's adjustment is inappropriate and is reversed by State Adjustment C-7 that I sponsor. After setting revised ongoing annual assessments, the FERC also ordered UE to pay a retroactive adjustment for interim assessment amounts underpaid for the historical study period 1980 through 2004, in the amount of $4,090,684, along with $241,738 in Study Costs associated with completing the headwater study. The Company's rate filing includes another $866,484 expense based upon a proposed 5-year amortization of this retroactive adjustment assessed by FERC and the related headwater study costs.

Q. Why should the Company not be allowed to recover the retroactive FERC assessment for headwater benefits as part of its revenue requirement?

A. These are prior period costs incurred by AmerenUE over the past 25 years that are not reflective of the ongoing cost of operating the Osage Plant. It would be inappropriate piecemeal and retroactive ratemaking to look back at cost changes in historical periods and increase future rates so the Company can be made whole for these isolated costs. Traditional ratemaking is forward looking and regulatory amortizations are usually created only when specific individually-significant events are brought to the attention of the regulator for special treatment, such as when catastrophic property losses are absorbed, extensive storm damage restoration is required, or when unique costs are incurred in connection with mergers or acquisitions requiring special deferral/amortization accounting treatment. To my knowledge, UE has not sought or received special accounting authority to defer and amortize or otherwise track changes in its FERC headwater benefits costs.

Q. Why is it problematic to allow a utility to select individual transactions for special treatment, in the way UE seeks to defer and amortize the 25-year true up of historical headwater benefit costs?

A. There are often opportunities to select individual transactions or types of costs for piecemeal ratemaking. Generally, a utility would elect to focus upon unique cost increases that would benefit shareholders if granted special regulatory deferral and amortization treatment. On the other hand, consumer advocate interests may elect to focus upon one-time events that would benefit consumers if singled out for special ratemaking treatment. The best regulatory response to such circumstances is to avoid piecemeal ratemaking and determine revenue requirement upon the best available measures of ongoing costs to provide utility services.

Q. Can you cite any specific examples of retroactive one-time transactions that could be singled out for special ratemaking treatment and that would benefit AmerenUE ratepayers if recognized?

A. Yes. In early 2006, the Company was a participant in certain litigation against the United States Department of Energy in connection alleged overcharges for nuclear fuel enrichment services. The AmerenUE share of a settlement that was achieved in this litigation was ** [redacted].**[16] Another example can be found in the resolution in 2005 of a dispute over mine reclamation issues with a coal supplier that resulted in Ameren recording a large after-tax gain. In its highly confidential response to Data Request No.

[16] AmerenUE HC response to Staff Data Request No. 237.

AG/UTI-98, the Company stated, **[redacted]**[17] In my view, the Company should not be allowed to retroactively charge its ratepayers for the FERC settlement associated with headwater benefits while electing to not credit ratepayers for these other retroactive settlement benefits that are being retained for shareholders.

## EMISSION ALLOWANCES

Q. Please describe Adjustment/Schedule C-8.

A. In its test year beginning point used to calculate revenue requirement in this Case, AmerenUE has included $3.9 million of income arising from gains realized by the Company from the sale of Emission Allowances. The Company has proposed no adjustment to this per book value and has no testimony explaining why this treatment is reasonable. I am proposing Adjustment C-8 to include a more representative four year average of actual emission allowance sales that have been made by the Company in the years 2003 through 2006.

Q. What is the Company's strategy and status with regard to emission allowances?

A. According to the highly confidential response to Data Request No. AG/UTI-57, *** [redacted]

[17] AmerenUE HC response to Data Request No. AG/UTI-98.

[redacted] ** This strategy has allowed the Company to accumulate an emission allowance ** [redacted] **

Q. Should proceeds from the sale of emission allowances be fully credited to the Company's ratepayers?

A. Yes. The costs to purchase and burn PRB compliance fuels, as well as all environmental facilities investment and expenses that are incurred are fully includable within the Company's operating expenses and/or rate base. Thus, all costs of Clean Air Act compliance incurred by AmerenUE have been recoverable from ratepayers. For example, during the test year, AmerenUE ** [redacted].**[18] To the extent that the Company's compliance strategy and such additional fuel costs result in the accumulation of banked allowances that can be profitably sold to third parties, the proceeds from such sales should be fully credited to ratepayers.

Q. What revenue amounts have been earned by AmerenUE from the sale of emission allowances since 2002?

A. According to the highly confidential Exhibit attached to the Company's response to Data Request No. AG/UTI 57, the following sales transactions have occurred:

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[18] AmerenUE Highly Confidential response to Data Request No. MPSC 325.

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[redacted]

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These amounts serve as the basis for the average proceeds included in revenue requirements as a result of the proposed State's adjustment.

Q. The Company's sales of emission allowances have varied significantly from year to year. What should be done to account for any variability in the level of such sales?

A. The level of emission allowances that are available for sale are influenced by the Company's fuel procurement strategies, primarily by the SO2 content of coal that is burned. Contract prices paid for PRB coal that is burned by AmerenUE are ** [redacted] ** For this reason, emission allowance sales proceeds can help to mitigate increases in the incurred cost of purchased coal.

In the event the Commission approves the new Fuel Adjustment Clause AmerenUE has proposed to track and recover changes in its fuel costs, it would be appropriate to also track changes in the level of emission allowance costs and revenues that are experienced by AmerenUE, relative to levels included in base rates. FAC tracking of changes in PRB coal prices as well as emission allowance costs and sales proceeds would achieve a balanced regulatory treatment of complementary resources used by Ameren in the conduct of its business.[19]

## INCOME TAX SECTION 199 DEDUCTION

Q. Please describe Adjustment/Schedule C-9.

A. Adjustment C-9 adjusts test year income tax expenses to recognize the new tax deduction available to electric utilities as a result of the American Jobs Creation Act of 2004 under Internal Revenue Code Section 199. An adjustment is necessary because the AmerenUE filing failed to account for this new income tax deduction.

Q. Please describe the new tax deduction available to electric utilities pursuant to IRC Section 199.

A. Starting with tax year 2005, a business may take a new deduction based upon a statutory percentage of its "qualified production activity income" ("QPAI"). Under section 199, the allowed deduction is equal to a percentage of the lesser of (a) income derived from qualified production activities for the taxable year ("QPAI") or (b) taxable income. The deduction percentage is three percent in 2005 and 2006, six percent in 2007-2009 and nine percent in 2010 when the deduction is fully phased in and is limited to 50 percent of W-2 Wages (as defined) paid during the calendar year ending during the taxpayer's taxable year.

QPAI is calculated by subtracting from domestic production gross receipts ("DPGR") for the taxable year (1) cost of goods sold ("CGS") that are allocable to such

19 The State of Missouri will address issues associated with FAC implementation in greater detail in its testimony to be separately filed on December 29.

receipts, (2) other deductions directly allocable to such receipts and (3) a ratable portion of other deductions. DPGR include gross receipts derived from any lease, rental, sale, exchange or other disposition of (a) qualifying production property ("QPP") (tangible personal property, computer software and sound recordings) which was manufactured, produced, grown or extracted ("MPGE") by the taxpayer in whole or in significant part within the U.S. and includes electricity, natural gas or potable water produced by the taxpayer in the U.S.[20]

Q. Why did AmerenUE not include any Section 199 tax deduction in its rate case filing?

A. According to the response to Data Request No. AG/UTI-30, "The Company did not recognize the tax benefit from the deduction under IRC section 1999 in the Company's asserted revenue requirements. The final regulations governing the calculation of the deduction were issued by the U.S. Treasury in May, 2006, and the Company did not finalize its computation of the deduction until August, 2006, after the asserted revenue requirements were filed with the MPSC."

Q. Since preparing its rate filing, has the Company actually filed its tax return reflecting a deduction pursuant to IRC section 199?

A. Yes. The Company included the deduction on the Company's federal and state income tax returns for 2005.[21]

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[20] IRC Section 199(a)(b)(c).
[21] AmerenUE response to Data Request No. AG/UTI-030.

Q. Has the Company prepared an estimate of its Section 199 tax deduction using information from its electric rate case filing?

A. Yes. In its response to Data Request AG/UTI-92, estimated deduction amounts were calculated by AmerenUE using consistent information from its rate filing. Those highly confidential calculations support a tax deduction of approximately ** [redacted] ** million when based upon the tax year 2006 statutory deduction percentage of 3 percent, which results in an income tax expense savings of about ** [redacted] ** million.

Q. Have you accepted these estimated amounts for inclusion in the State's calculated AmerenUE revenue requirement?

A. I have accepted the calculations of QPAI proposed by the Company, but have applied the higher 2007 tax year statutory deduction rate of 6% to maintain consistency with the balance of test year cutoffs employed in this proceeding.

Q. Why should the 2007 tax deduction percentage be used, rather than the lower statutory deduction percentage applicable in 2006?

A. I understand that AmerenUE desires an updated calculation of its Plant in Service to the beginning of year 2007 (12/31/2006) and desires an updated accounting of its increasing delivered coal prices to levels in effect in January 2007. The increase in Section 199 tax deduction provisions is a known and measurable change effective at that same time that should not be ignored in calculating an internally consistent test year update in early 2007.

## PRODUCTION PLANT RETIREMENT ASSUMPTIONS

Q. Please describe Adjustment/Schedule C-15.

A. Adjustment C-15 annualizes depreciation expense for the test year using existing, MPSC-approved depreciation accrual rates. The mechanics of this adjustment are actually sponsored by and explained by Mr. Carver. My testimony at this time addresses the need to recognize an expectation that the remaining useful life of the Callaway Station will be extended upon re-licensing of the plant for continued operations and that UE has no defined plan for mass retirement of all of its large, coal-fired generating units.

Q. Has Utilitech performed any depreciation studies to evaluate the reasonableness of the Company's existing depreciation accrual rates?

A. No. However, I understand that UE has submitted a depreciation accrual rate study that is sponsored by its witnesses Messrs. John F. Wiedemayer and William M. Stout. Utilitech was <u>not</u> retained to analyze depreciation accrual rates and Mr. Carver has not included any revisions to the currently effective, MPSC-approved depreciation accrual rates in his calculations. My testimony on this topic is limited to the assumptions employed by UE to project future retirement dates for the Callaway nuclear generating unit and for the Company's other coal-fired generating units, which dates were used by the Company in developing proposed changes to depreciation accrual rates.

Q. What is the status of Callaway's Nuclear Regulatory Commission ("NRC") operating license?

A. Callaway commenced commercial operation in 1984, after being granted the standard 40-year NRC operating license. The initial plant license is scheduled to expire in about 18 years in 2024, unless the license is extended for another 20 years. According to UE witness Mr. Naslund, "As of now, AmerenUE has made no decision as to whether it should request an extension of the Callaway license." [22]

Q. Is it unusual for nuclear units comparable to Callaway to request and receive NRC license extensions?

A. No. According to information summarized on the NRC web site, there have been 44 license extensions granted to utilities with operating nuclear plants and another 10 license extension applications are pending. I have attached as Schedule MLB-3 a copy of a document titled, <u>Backgrounder – Reactor License Renewal</u> from the NRC web site that contains a summary of License Renewal Applications starting at page 6 of the document. Notably, the nuclear unit most comparable to Callaway is the Wolf Creek unit that has already applied for its NRC license extension in October of 2006, as noted on page 9 of this document. This information was confirmed by UE in its response to Data Request No. AG/UTI-187, where the Company identified only 12 nuclear units for which licenses were not extended and plans for decommissioning are in progress. In that response, Mr. Naslund stated, "Based on information known at this time, I would expect that AmerenUE would continue to keep its option open to pursue a license extension for Callaway."

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[22] Direct Testimony of Charles D. Naslund, page 9.

Q. What is the significance of AmerenUE's position that it "has made no decision" with regard to the Callaway license extension?

A. The Company is seeking higher depreciation expense at this time for Callaway because of the presumption that the unit will be retired at the end of the initial 40-year operating license, even though no decision has been made to not seek a license extension. According to the Direct Testimony of UE witness Mr. William Stout, "The retirement date for Callaway is October, 2024. The basis for this date is the expiration of the license to operate the plant." While Mr. Stout admits that "...it is possible that the operating license will be extended" he argues that "There are numerous uncertainties that could affect the decision to extend the license when it expires 18 years from now" and "...even if the license is extended, it may come with a price. That is, AmerenUE may be required to expend significant sums in order to comply with the terms of the extended license including the replacement of plant currently in service."[23]

Q. What is the current Commission-approved depreciation accrual rate for Callaway and what changes to the Callaway plant depreciation accruals are reflected in calculating Callaway depreciation in UE's asserted revenue requirement?

A. The currently effective Callaway depreciation accrual rate is 2.6 percent for all nuclear plant accounts.[24] In its depreciation study, AmerenUE Schedule JFW-E1, page III-5, an annual depreciation accrual for Callaway assets is proposed of $85,268,244. To this amount, an amortization of a positive "Reserve Variance" of $8,500,864 at page III-10 is added, yielding a "Total Annual Depreciation Amount" for Callaway of $93,769,108 on

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23 Direct Testimony of William M. Stout, pages 29-31.
24 AmerenUE Workpaper GSW-WP-E1335

page III-16 that translates into the Company's new proposed annual accrual rates that are equivalent to a composite rate of 3.44 percent. The test year effect of this dramatic increase in nuclear depreciation is an increase of $22,965,000 as shown at Mr. Weiss' Schedule GSW-E30-2 at line 17.

Q. What causes the large increase in UE's proposed annual nuclear plant depreciation expense accrual, if there has been no change in the term of the existing operating license for the plant?

A. Significant additional investments have been made at Callaway, which were apparently not anticipated or provided for in the establishment of accrual rates used to depreciate the plant in past years. One recent example of such investments would be the steam generator replacement and turbine upgrade projects that are discussed in Mr. Naslund's testimony.[25] Accounting for such interim additions, with no assumed extension of the planned retirement date, requires an increase in depreciation accruals to recover these investments over the remaining useful life of the plant.

Q. If Callaway's operating license is extended by the NRC, upon application by AmerenUE, would it be possible to reduce the required annual depreciation accrual for the plant?

A. Yes. A license extension of 20 years would allow the costs of interim additions, as well as the large initial investment made at Callaway to be spread over about 38 future years, instead of the 18 years remaining under the existing plant license. Even if significant additional interim investments are required in the future at Callaway, the approximate

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[25] Direct Testimony of Charles D. Naslund, page 6. See also Schedule CDN-1-1 through CDN-1-3 for a listing of other nuclear plant projects since 2000.

doubling of the remaining life of the plant would likely produce dramatic reductions in required annual depreciation accruals. In Data Request No. AG/UTI-184, AmerenUE was asked to identify any specific types and amounts of new expenditures that would likely be required of AmerenUE to comply with the terms of any license extension that may be requested for Callaway and the Company responded, "Ameren has not begun to consider the expenditures that would be required as it would be premature to do so."

Q. Given the uncertainties regarding whether or not AmerenUE will request or receive an operating license extension for Callaway, what is your recommendation with regard to the annual depreciation accrual rates for the plant?

A. At a minimum, the Commission should not accept any increase in the annual accrual rates for the Callaway unit at this time. It is not reasonable for the Company to resist making a decision or commitment regarding re-licensing at the same time it proposes to increase annual revenue requirements by nearly $23 million based upon an assumption that the license will not be extended. Therefore, I have asked Mr. Carver to <u>not change</u> the existing Commission-approved nuclear depreciation accrual rates within the State's revenue requirement calculations until a re-licensing decision is made and the associated known and measurable retirement date for Callaway becomes known.

In the alternative, if the Commission determines it appropriate to revise the Callaway depreciation accrual rates at this time, care should be taken to account for the reasonable expectation that NRC license extension will be requested and granted, as an offset to upward pressure on nuclear depreciation accruals caused by interim additions. This approach has not been quantified in the State's evidence, but appears to be a more reasonable alternative than AmerenUE's one-sided approach that assumes premature retirement of a valuable generating resource that is not consistent with the industry trends toward widespread nuclear plant re-licensing.

Q. Earlier in your testimony, you noted that operators of the Wolf Creek plant have already filed for an NRC license extension. What is the significance of this fact?

A. The Callaway and Wolf Creek plants have the same design for that part of the plant referred to as the power block.[26] According to Mr. Naslund's testimony at page 9, "The single most critical consideration in determining whether or not relicensing may be feasible is the condition of the reactor vessel itself. Extensive monitoring is in place to measure neutron embrittlement of the vessel wall."

In its response to Data Request AG/UTI-189, the Company stated, "Callaway's reactor vessel is periodically surveiled through a capsule specimen surveillance program. Callaway's most recent surveillance results show shelf life energies that equate to a vessel life good for greater than 80 years. We are not aware of Wolf Creek's vessel status." Thus, available information regarding the single most important consideration to determine the feasibility of Callaway relicensing is that Callaway's reactor vessel is good for greater than 80 years life meeting the NRC standard for relicensing the vessel for 60 years use.[27]

[26] UE response to Data Request AG/UTI-185.

[27] UE response to Data Request AG/UTI-189. In this response, UE explains actions that are expected to be needed to mitigate problems with certain alloy 600 welds upon relicensing, as well as anticipated reactor vessel head replacement that will be required before license extension will be accepted.

Q. Has Kansas City Power and Light Company, as an owner of Wolf Creek, already reduced its annual depreciation accruals as well as annual decommissioning accruals for Missouri ratemaking purposes as a result of anticipated re-licensing of that plant?

A. Yes. Even though the Wolf Creek NRC re-licensing application was only recently filed, that utility's Missouri rates already reflect the economic benefits of the expected approval of an NRC license extension if the Staff proposal and Company's decommissioning changes are recognized by the Commission.[28] It is my understanding that the Kansas Corporation Commission first recognized the anticipated Wolf Creek license extension in setting utility rates for Kansas Gas & Electric Company and for Kansas City Power and Light back in 2001.[29]

Q. Has AmerenUE been incurring O&M expenses on surveillance work to track Callaway component life values which will be necessary to provide a basis for extension of Callaway's license?

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28 In a Stipulation approved in MPSC Case No. EO-2005-0329, KCPL agreed to "begin recording depreciation expense for the Wolf Creek Nuclear Genreating Station based on a 60-year life span" (page 24), resulting in annual accrual rates ranging from 1.55% to 2.36% (Appendix G-1). In the pending KCPL Missouri rate case, Case No. ER-2006-0314, Staff witness Ms. Rosella L. Schad stated in Direct Testimony that the basis for Wolf Creek depreciation rates is, "...the expected extension of the nuclear units' operating license from 40 years to 60 years (Schedule 5), plus an allowance for interim net salvage. In his Direct Testimony at pages 25-26, Mr. Frerking recommends reducing decommission accruals for Wolf Creek but notes that in the event Wolf Creek re-licensing is not ultimately approved by the NRC, adjustments will be required in future cases.

29 See Kansas Corporation Commission Order on Rate Applications, Docket No. 01-WSRE-436-RTS, "29. In adopting the Majoros study, the Commission is assuming that the Wolf Creek nuclear plant will request and obtain a 20-year license extension from the Nuclear Regulatory Commission (NRC). Because Wolf Creek cannot apply for a license extension until 2005, the Applicants argue that it is premature to increase the useful life of Wolf Creek. (Aikman rebuttal, 9.)" In paragraph 31, the Order states, "The Commission finds that Aikman's standard that t he license actually be renewed before the plants' depreciation life can be extended to be unreasonable. Nuclear power plant license extensions are widely predicted now, and the clear trend has been to grant license extensions. (Transcript, 1369-72, 2188-90.) the information known about Wolf Creek strongly supports the conclusion that the Wolf Creek license will be extended for an additional 20 years by the NRC."

A. Yes. In its response to Data Request No. AG/UTI-190, the Company identified a listing of monitoring activities and tests used to track component life. The expenses for this activity have been significant historically and are expected to grow to more than $4 million per year in 2007 and in 2010 as the alloy 600 weld issues are examined. Some of these costs have likely been included in test year results, to be recovered in the Company's revenue requirement.

Q. What has the Company assumed with regard to future retirement dates for its coal-fired steam generating units at Labadie, Sioux, Meramec and Rush Island stations?

A. In its depreciation accrual rate study that is sponsored by UE witness Mr. Wiedmayer, the Company assumes that, "The probable retirement date used for all steam production plants is June 30, 2026."[30] Thus, in determining remaining life spans for the majority of the Company's installed non-nuclear baseload generating capacity, the entire fleet of units is assumed to be retired in less than 20 years from now.

Q. Is the presumed retirement of AmerenUE's entire coal-fired generating fleet a reasonable assumption at one time in less than 20 years from now a credible assumption, in your opinion?

A. No. Performance of the AmerenUE coal-fired generators is touted by UE witness Mr. Birk as favorable and improving and he states that the Company faces a continuing need for more generating capacity.[31] In Section IV of his Direct Testimony, Mr. Birk explains several initiatives that have been implemented to improve steam production plant

30 UE Schedule JFW-E1, page II-25.

31 Birk Direct Testimony, page 8-13.

reliability, availability, and operational performance, including the Plant Maintenance Optimization (PMO), Plant Reliability Optimization (PRO), and Corrective Action Process (CAP) programs which have helped AmerenUE improve overall plant capability, availability, and capacity factors. According to Mr. Birk, AmerenUE needs to periodically add generation capability to meet growing demand for reliable service and has recently added significantly to its peaking capacity, while no new baseload capacity has been added since 1984.[32] There is no suggestion within Mr. Birk's testimony that AmerenUE is contemplating any reduced O&M, capital or environmental compliance support for its coal-fired baseload units, or that retirement is being considered for any of such units in the foreseeable future.

Q. Is the retirement of all of UE's coal-fired baseload generation in 2026, as assumed in the Company's depreciation study, consistent with the Company's most current generation plan?

A. No. In its highly confidential response to Staff Data Request No. 75, the Company stated, ** [redacted] ** While it is theoretically possible for mass retirement of the entire fleet of coal-fired generators to occur in the subsequent year, as assumed for depreciation study purposes, it is highly unlikely that UE could plan such an effort, finance the resulting huge construction bill, or mobilize resources to physically manage such an ambitious undertaking.

32 Direct Testimony of Mark C. Birk, page 15.

Q. Does the Company have any specific plans at this time to retire and replace any of its steam generating plants?

A. ** [redacted].[33] **

**PINCKNEYVILLE & KINMUNDY PLANT ACQUISITION**

Q. Please describe AmerenUE's Pinckneyville and Kinmundy generating units.

A. The Pinckneyville, Illinois generating facility consists of eight combustion turbine generator units with a total capacity of 316 MW and the Kinmundy, Illinois generating facility consists of two combustion turbine units with a total capacity of 232 MW. Both facilities were purchased by AmerenUE from its affiliate, Ameren Energy Generating Company ("AEG") at their net book value, which as of September 30, 2002 was $161.5 million for Pinckneyville and $96.4 million for Kinmundy.[34]

Q. When did the actual transfer of the Pinckneyville and Kinmundy plants occur?

A. The Asset Transfer Agreements for the transactions were dated as of May 2, 2005 and the Company's SEC Form 10-K report disclosed the expenditure to acquire the plants in the year 2005.

Q. What was the cost per KW associated with AmerenUE's acquisition of these facilities from its corporate affiliate?

A. Using the information from my previous response, the cost of the acquired capacity was $511 per KW at Pinckneyville and $416 per KW at Kinmundy.

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[33] AmerenUE Highly Confidential response to Data Request No. AG/UTI-236.

[34] AmerenUE response to Data Request No. AG/UTI-24, testimony of Richard A. Voytas in FERC Docket No. EC03-53-000, at pages 3-4.

Q. Has the transfer of capacity from Ameren Energy Generating Company to AmerenUE been previously reviewed or approved by Federal or Missouri regulators?

A. AEG and AmerenUE submitted an Application for FERC approval in Docket Nos. EC03-53-000 and EC03-53-001 and the transfer was approved by the FERC in its Opinion No. 473.[35] The Missouri PSC was granted late intervention in the referenced FERC case and submitted two letters dated March 18, 2003 and June 3, 2003 in which the Commission clarified its intentions. Copies of these letters are included in Schedule MLB-4 attached to this testimony. In these letters, the Commission indicated its intent to scrutinize the Pinckneyville and Kinmundy transfers in greater detail in this rate case proceeding, stating in the March 18 letter, "At the time the costs from this transaction are considered for ratemaking purposes, AmerenUE will be responsible to demonstrate that this transaction was prudent and reasonable in light of other available options" and in the June 3 letter, "…the prudency of this transaction will be reviewed by the Missouri Commission. AmerenUE agrees that the Missouri Commission has the authority to fully analyze the prudency of this proposed transaction, including , but not limited to, the timing of the purchase, the amount of the purchase, the need for the purchase, and the appropriateness of the purchase in light of other options, including purchase on the market or acquisition of other assets. In exercising this authority, the Missouri Commission is confident that it can protect the interest of ratepayers and shareholders."

[35] 108 FERC ¶61,081.

Q. Did the FERC rely upon the Missouri Commission's representations that it would conduct a prudence examination of the subject transactions in rendering its Opinion on the matter?

A. It is not clear that the FERC relied upon the MPSC letters in rendering its decision. The focus at FERC appears to have been upon competitive issues more than ratemaking concerns. At paragraph 48 of its Opinion No. 473, the FERC Stated:

> 48. The Commission recognizes that effective regulatory review at the federal and state levels can prevent excessive rates to wholesale and retail customers respectively of the acquiring utility. However, our obligation under section 203 is to decide at the time a transaction is filed, and before it is consummated, whether the transaction will adversely affect competition and is consistent with the public interest. While effective state regulatory review can prevent excessive rates to the retail customers of the acquiring utility, it is not a remedy for anticompetitive effects of affiliate preference, which harm all customers. The possibility of eventual regulatory review does not prevent the exercise of affiliate preference before the transaction occurs. We are also not convinced that such eventual regulatory review of rates is an effective remedy for anticompetitive effects that arise at the time affiliate preference occurs. Ultimately all customers are harmed because competition is undermined.

This FERC Opinion then prescribed "Guidelines for Reviewing Future Section 203 Affiliate Transactions" and contained ordering paragraphs that affirmed approval of the asset transfers "without prejudice to the authority of the Commission or any other regulatory body with respect to rates, service, accounts, valuation, estimates or determinations of costs, or any other matter whatsoever now pending or which may come before the Commission".[36]

Q. Has AmerenUE demonstrated in its prefiled evidence that the Pinckneyville and Kinmundy affiliate transactions were prudent and reasonable in light of other options?

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[36] Id.

A. No. There is no testimony regarding these plant acquisitions from the AEG affiliate in 2005 at prices exceeding $400 per KW. Instead, AmerenUE witness Mr. Moehn discusses, at pages 3 through 10 of his Direct Testimony, the reasonableness of the Company's acquisition in 2005 of combustion turbine generating facilities from NRG and Aquila at prices averaging $200 and $260 per KW respectively.

Q. Has the Commission undertaken any prudence review of the Pinckneyville or Kinmundy capacity acquisitions from AEG?

A. In its response to State of Missouri AGP Data Request No. 1000, the Staff stated that, "As part of Staff's audit in Case No. ER-2007-0002, the Staff has been reviewing materials relating to AmerenUE's acquisition of generating plant at Pinckneyville and Kinmundy. In its review the Staff has submitted to AmerenUE Staff Data Request No. 448, a copy of which follows…The Staff has not received as yet a response from AmerenUE to Staff Data Request No. 448." Staff also stated in this response the following:

> The Staff's review is ongoing, and, as indicated above, the Staff has not yet received a response from AmerenUE to Staff Data Request No. 448. Although the Staff has not reached a final conclusion, it is currently of the opinion that the cost of the transfer of the Pinckneyville and Kinmundy units to AmerenUE was above the cost that UE would have incurred to build these units. The Staff has reached this determination by a review of the cost of units elsewhere that are deemed comparable to those units transferred to AmerenUE at Pinckneyville and Kinmundy. The Staff will be proposing an adjustment to reduce the cost of the Pinckneyville and Kinmundy unit transfers to a reasonable level comparable to the cost of similar units elsewhere.

Other documents were transmitted with this Staff response, including the Commission's letters to FERC described above, as well as a June 2005 Appraisal Report procured by Ameren in connection with a different combustion turbine acquisition transaction.

Q. Have you conducted a prudence investigation with respect to the prices paid by AmerenUE to acquire the Pinckneyville and Kinmundy facilities from the AEG affiliate?

A. No. However, I have examined comparable pricing information for transactions involving combustion turbine capacity that was compiled by AmerenUE and provided in its confidential response to Data Request No. AG/UTI-94. That information supports a conclusion that AmerenUE paid higher than prevailing market prices in its acquisition of capacity from its affiliate, AEG when the transactions closed in 2005.

Q. What is the relevance of prevailing market prices in connection with affiliate transfers of assets into utility rate base?

A. The Commission's affiliate transaction rules require assets acquired by a utility from an affiliated company to be priced at the lower of cost or market value.[37] With respect to the Pinckneyville and Kinmundy transactions, AmerenUE paid a price that was equivalent to the selling affiliate's net book cost in the assets, effectively making the affiliate "whole" on its investment in the facilities, at a time when "market" prices appear to have been considerably lower.

[37] 4 CSR 240-15 (2)(A)(1) prohibits a regulated electrical corporation from compensating an affiliated entity above the lesser of "fair market price" or "the fully distributed cost to the regulated electrical corporation to provide the goods or services for itself"

Q. Have you prepared an adjustment to reduce the cost of the Pinckneyville and Kinmundy plant assets to a level more consistent with apparent market values?

A. Yes. Adjustment/Schedule B-3 reflects a reduction in AmerenUE rate base to re-value the cost basis of the Pinckneyville and Kinmundy generating assets, based upon an average of transaction prices for combustion turbine generating facility transfers between non-affiliated entities that occurred in 2003, 2004 or 2005. The input data used in these calculations at lines 6 through 13 was compiled by AmerenUE and was provided in its confidential response to Data Request No. AG/UTI-94. A corresponding Adjustment/Schedule C-10 reflects the reduction in book depreciation expense associated with the revised valuation of the Pinckneyville and Kinmundy generating assets at presently effective depreciation accrual rates.

Q. How do the results of your calculations compare to the June 2005 Appraisal Report that was prepared for AmerenUE by its consultant to evaluate the fair market value of combustion turbine assets acquired at its Venice Power plant?

A. R. W. Beck was retained by AmerenUE to evaluate the fair market value of combustion turbine generating assets that is acquired for its Venice Station. In its report dated June 8, 2005, R. W. Beck indicated a Fair Market Value for a single 117MW combustion turbine to be as $25,458,000 or $217 per MW, based upon the estimated replacement cost for the assets.[38] In contrast, I have adjusted the Pinckneyville and Kinmundy valuation downward to $288 per MW, based upon a broader average of comparable combustion turbine sales transactions between non-affiliated parties in the years 2003 through 2005.

38 AmerenUE response to Data Request No. AG/UTI-24(b), Appraisal Report Section 5.1 "Fair Market Value"

Q. Is the adjustment you propose provisional, subject to a showing by AmerenUE that the prices it paid to its AEG affiliate for Pinckneyville and Kinmundy plant assets were not unreasonable and were, in fact, compliant with the Commission's affiliated interest rules?

A. Yes. Even though no evidence is contained in AmerenUE's rate case filing in support of these transactions, I would invite the Commission to consider additional facts and circumstances supplied by AmerenUE, as well as the results of Staff's prudence review, in finalizing a reasonable ratemaking valuation for these assets.

Q. Does this conclude your direct testimony?

A. Yes.

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

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

AFFIDAVIT OF MICHAEL L. BROSCH

STATE OF MISSOURI )
) ss
COUNTY OF JACKSON )

Michael L. Brosch, being of lawful age, on his oath states: that he has participated in the preparation of the foregoing Direct Testimony in question and answer form to be presented in the above case; that the answers in said Direct Testimony were given by him; that he has knowledge of the matters set forth in such answers; and that such matters are true and correct to the best of his knowledge and belief.

Michael L. Brosch

Subscribed and sworn to before me this 14th day of December, 2006.

Lori M. Rice
Notary

NOTARY PUBLIC NOTARY SEAL STATE OF MISSOURI

LORI M. RICE
My Commission Expires
June 7, 2010
Jackson County
Commission #06897298

**Michael L. Brosch**
Utilitech, Inc. – President
Bachelor of Business Administration (Accounting)
University of Missouri-Kansas City (1978)
Certified Public Accountant Examination (1979)

## GENERAL

Mr. Brosch serves as the director of regulatory projects for the firm and is responsible for the planning, supervision and conduct of firm engagements. His academic background is in business administration and accounting and he holds CPA certificates in Kansas and Missouri.

## EXPERIENCE

Mr. Brosch has supervised and conducted the preparation of rate case exhibits and testimony in support of revenue requirements of electric, gas, telephone, water, and sewer utilities in response to tariff change proposals as a consultant and while employed by the Missouri Commission Staff. Responsible for virtually all facets of revenue requirement determination cost of service allocations and tariff implementation in addition to involvement in numerous special project investigations.

Industry restructuring analysis for gas utility rate unbundling, deregulation, competitive bidding and strategic planning, with testimony on regulatory processes, asset identification and classification, revenue requirement and unbundled rate designs and class cost of service studies.

Responsible for analysis and presentation of income tax related issues within ratemaking proceedings involving interpretation of relevant IRS code provisions and regulatory restrictions.

Conducted extensive review of the economic impact upon regulated utility companies of various transactions involving affiliated companies. Reviewed the parent-subsidiary relationships of integrated utility holding companies to determine appropriate treatment of consolidated tax benefits and capital costs. Sponsored testimony on affiliated interests in numerous Bell and major independent telephone company rate proceedings.

Has substantial experience in the application of lead-lag study concepts and methodologies in determination of working capital investment to be included in rate base.

Alternative regulation analyses and consultation to clients in Arizona, California and Oklahoma, focused upon challenges introduced by cost-based regulation, incentive effects available through alternative regulation and balancing of risks, opportunities and benefits among stakeholders.

Mr. Brosch managed the detailed regulatory review of utility mergers and acquisitions, diversification studies and holding company formation issues in energy and telecommunications transactions in multiple states. Sponsored testimony regarding merger synergies, merger accounting and tax implications, regulatory planning and price path strategies. Traditional horizontal utility mergers as well as leveraged buyouts of utility properties by private equity investors were addressed in several states.

Analyzed the regulation of telephone company publishing affiliates, including the propriety of continued imputation of directory publishing profits and the valuation of publishing affiliates, including the identification and quantification of intangible assets and benefits of affiliation with the regulated business in Arizona, Indiana, Washington and Utah.

## WORK HISTORY

| | |
|---|---|
| 1985 - Present | **Principal** - Utilitech, Inc. (Previously Dittmer, Brosch and Associates, Inc.) |
| 1983 - 1985: | **Project manager** - Lubow McKay Stevens and Lewis. Responsible for supervision and conduct of utility regulatory projects on behalf of industry and regulatory agency clients. |
| 1982 - 1983: | **Regulatory consultant** - Troupe Kehoe Whiteaker and Kent. Responsible for management of rate case activities involving analysis of utility operations and results, preparation of expert testimony and exhibits, and issue development including research and legal briefs. Also involved in numerous special projects including financial analysis and utility systems planning. Taught firm's professional education course on "utility income taxation - ratemaking and accounting considerations" in 1982. |
| 1978 - 1982: | **Senior Regulatory Accountant** - Missouri Public Service Commission. Supervised and conducted rate case investigations of utilities subject to PSC jurisdiction in response to applications for tariff changes. Responsibilities included development of staff policy on ratemaking issues, planning and evaluating work of outside consultants, and the production of comprehensive testimony and exhibits in support of rate case positions taken. |

## OTHER QUALIFICATIONS

Bachelor of Business Administration - Accounting, 1978
University of Missouri - Kansas City "with distinction"

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|---|---|
| Member | American Institute of Certified Public Accountants<br>Missouri Society of Certified Public Accountants<br>Kansas Society of Certified Public Accountants |
| Attended | Iowa State Regulatory Conference 1981, 1985<br>Regulated Industries Symposium 1979, 1980<br>Michigan State Regulatory Conference 1981<br>United States Telephone Association Round Table 1984<br>NARUC/NASUCA Annual Meeting 1988, Speaker<br>NARUC/NASUCA Annual Meeting 2000, Speaker |
| Instructor | INFOCAST Ratemaking Courses<br>Arizona Staff Training<br>Hawaii Staff Training |

# Michael L. Brosch
## Summary of Previously Filed Testimony

| Utility | Jurisdiction | Agency | Docket/Case Number | Represented | Year | Addressed |
|---|---|---|---|---|---|---|
| Green Hills Telephone Company | Missouri | PSC | TR-78-282 | Staff | 1978 | Rate Base, Operating Income |
| Kansas City Power and Light Co. | Missouri | PSC | ER-78-252 | Staff | 1978 | Rate Base, Operating Income |
| Missouri Public Service Company | Missouri | PSC | ER-79-59 | Staff | 1979 | Rate Base, Operating Income |
| Nodaway Valley Telephone Company | Missouri | PSC | 16,567 | Staff | 1979 | Rate Base, Operating Income |
| Gas Service Company | Missouri | PSC | GR-79-114 | Staff | 1979 | Rate Base, Operating Income |
| United Telephone Company | Missouri | PSC | TO-79-227 | Staff | 1979 | Rate Base, Operating Income |
| Southwestern Bell Telephone Co. | Missouri | PSC | TR-79-213 | Staff | 1979 | Rate Base, Operating Income |
| Missouri Public Service Company | Missouri | PSC | ER-80-118 GR-80-117 | Staff | 1980 | Rate Base, Operating Income |
| Southwestern Bell Telephone Co. | Missouri | PSC | TR-80-256 | Staff | 1980 | Affiliate Transactions |
| United Telephone Company | Missouri | PSC | TR-80-235 | Staff | 1980 | Affiliate Transactions, Cost Allocations |
| Kansas City Power and Light Co. | Missouri | PSC | ER-81-42 | Staff | 1981 | Rate Base, Operating Income |
| Southwestern Bell Telephone | Missouri | PSC | TR-81-208 | Staff | 1981 | Rate Base, Operating Income, Affiliated Interest |
| Northern Indiana Public Service | Indiana | PSC | 36689 | Consumers Counsel | 1982 | Rate Base, Operating Income |
| Northern Indiana Public Service | Indiana | URC | 37023 | Consumers Counsel | 1983 | Rate Base, Operating Income, Cost Allocations |
| Mountain Bell Telephone | Arizona | ACC | 9981-E1051-81-406 | Staff | 1982 | Affiliated Interest |
| Sun City Water | Arizona | ACC | U-1656-81-332 | Staff | 1982 | Rate Base, Operating Income |
| Sun City Sewer | Arizona | ACC | U-1656-81-331 | Staff | 1982 | Rate Base, Operating Income |
| El Paso Water | Kansas | City Counsel | Unknown | Company | 1982 | Rate Base, Operating Income, Rate of Return |
| Ohio Power Company | Ohio | PUCO | 83-98-EL-AIR | Consumer Counsel | 1983 | Operating Income, Rate Design, Cost Allocations |
| Dayton Power & Light Company | Ohio | PUCO | 83-777-GA-AIR | Consumer Counsel | 1983 | Rate Base |
| Walnut Hill Telephone | Arkansas | PSC | 83-010-U | Company | 1983 | Operating Income, Rate Base |
| Cleveland Electric Illum. | Ohio | PUCO | 84-188-EL-AIR | Consumer Counsel | 1984 | Rate Base, Operating Income, Cost Allocations |
| Cincinnati Gas & Electric | Ohio | PUCO | 84-13-EL-EFC | Consumer Counsel | 1984 | Fuel Clause |
| Cincinnati Gas & Electric | Ohio | PUCO | 84-13-EL-EFC (Subfile A) | Consumer Counsel | 1984 | Fuel Clause |
| General Telephone - Ohio | Ohio | PUCO | 84-1026-TP-AIR | Consumer Counsel | 1984 | Rate Base |
| Cincinnati Bell Telephone | Ohio | PUCO | 84-1272-TP-AIR | Consumer Counsel | 1985 | Rate Base |
| Ohio Bell Telephone | Ohio | PUCO | 84-1535-TP-AIR | Consumer Counsel | 1985 | Rate Base |

Michael L. Brosch
Summary of Previously Filed Testimony

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|---|---|---|---|---|---|---|
| United Telephone - Missouri | Missouri | PSC | TR-85-179 | Staff | 1985 | Rate Base, Operating Income |
| Wisconsin Gas | Wisconsin | PSC | 05-UI-18 | Staff | 1985 | Diversification-Restructuring |
| United Telephone - Indiana | Indiana | URC | 37927 | Consumer Counsel | 1986 | Rate Base, Affiliated Interest |
| Indianapolis Power & Light | Indiana | URC | 37837 | Consumer Counsel | 1986 | Rate Base |
| Northern Indiana Public Service | Indiana | URC | 37972 | Consumer Counsel | 1986 | Plant Cancellation Costs |
| Northern Indiana Public Service | Indiana | URC | 38045 | Consumer Counsel | 1986 | Rate Base, Operating Income, Cost Allocations, Capital Costs |
| Arizona Public Service | Arizona | ACC | U-1435-85-367 | Staff | 1987 | Rate Base, Operating Income, Cost Allocations |
| Kansas City, KS Board of Public Utilities | Kansas | BPU | 87-1 | Municipal Utility | 1987 | Operating Income, Capital Costs |
| Detroit Edison | Michigan | PSC | U-8683 | Industrial Customers | 1987 | Income Taxes |
| Consumers Power | Michigan | PSC | U-8681 | Industrial Customers | 1987 | Income Taxes |
| Consumers Power | Michigan | PSC | U-8680 | Industrial Customers | 1987 | Income Taxes |
| Northern Indiana Public Service | Indiana | URC | 38365 | Consumer Counsel | 1987 | Rate Design |
| Indiana Gas | Indiana | URC | 38080 | Consumer Counsel | 1987 | Rate Base |
| Northern Indiana Public Service | Indiana | URC | 38380 | Consumers Counsel | 1988 | Rate Base, Operating Income, Rate Design, Capital Costs |
| Terre Haute Gas | Indiana | URC | 38515 | Consumers Counsel | 1988 | Rate Base, Operating Income, Capital Costs |
| United Telephone -Kansas | Kansas | KCC | 162,044-U | Consumers Counsel | 1989 | Rate Base, Capital Costs, Affiliated Interest |
| US West Communications | Arizona | ACC | E-1051-88-146 | Staff | 1989 | Rate Base, Operating Income, Affiliate Interest |
| All Kansas Electrics | Kansas | KCC | 140,718-U | Consumers Counsel | 1989 | Generic Fuel Adjustment Hearing |
| Southwest Gas | Arizona | ACC | E-1551-89-102 E-1551-89-103 | Staff | 1989 | Rate Base, Operating Income, Affiliated Interest |
| American Telephone and Telegraph | Kansas | KCC | 167,493-U | Consumers Counsel | 1990 | Price/Flexible Regulation, Competition, Revenue Requirements |
| Indiana Michigan Power | Indiana | URC | 38728 | Consumer Counsel | 1989 | Rate Base, Operating Income, Rate Design |
| People Gas, Light and Coke Company | Illinois | ICC | 90-0007 | Public Counsel | 1990 | Rate Base, Operating Income |
| United Telephone Company | Florida | PSC | 891239-TL | Public Counsel | 1990 | Affiliated Interest |
| Southwestern Bell Telephone Company | Oklahoma | OCC | PUD-000662 | Attorney General | 1990 | Rate Base, Operating Income (Testimony not admitted) |
| Arizona Public Service Company | Arizona | ACC | U-1345-90-007 | Staff | 1991 | Rate Base, Operating Income |
| Indiana Bell Telephone Company | Indiana | URC | 39017 | Consumer Counsel | 1991 | Test Year, Discovery, Schedule |
| Southwestern Bell Telephone Company | Oklahoma | OCC | 39321 | Attorney General | 1991 | Remand Issues |

Michael L. Brosch
Summary of Previously Filed Testimony

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|---|---|---|---|---|---|---|
| UtiliCorp United/ Centel | Kansas | KCC | 175,476-U | Consumer Counsel | 1991 | Merger/Acquisition |
| Southwestern Bell Telephone Company | Oklahoma | OCC | PUD-000662 | Attorney General | 1991 | Rate Base, Operating Income |
| United Telephone - Florida | Florida | PSC | 910980-TL | Public Counsel | 1992 | Affiliated Interest |
| Hawaii Electric Light Company | Hawaii | PUC | 6999 | Consumer Advocate | 1992 | Rate Base, Operating Income, Budgets/Forecasts |
| Maui Electric Company | Hawaii | PUC | 7000 | Consumer Advocate | 1992 | Rate Base, Operating Income, Budgets/Forecasts |
| Southern Bell Telephone Company | Florida | PSC | 920260-TL | Public Counsel | 1992 | Affiliated Interest |
| US West Communications | Washington | WUTC | U-89-3245-P | Attorney General | 1992 | Alternative Regulation |
| UtiliCorp United/ MPS | Missouri | PSC | ER-93-37 | Staff | 1993 | Affiliated Interest |
| Oklahoma Natural Gas Company | Oklahoma | OCC | PUD-1151, 1144, 1190 | Attorney General | 1993 | Rate Base, Operating Income, Take or Pay, Rate Design |
| Public Service Company of Oklahoma | Oklahoma | OCC | PUD-1342 | Staff | 1993 | Rate Base, Operating Income, Affiliated Interest |
| Illinois Bell Telephone | Illinois | ICC | 92-0448 92-0239 | Citizens Board | 1993 | Rate Base, Operating Income, Alt. Regulation, Forecasts, Affiliated Interest |
| Hawaii Electric Company | Hawaii | PUC | 7700 | Consumer Advocate | 1993 | Rate Base, Operating Income |
| US West Communications | Arizona | ACC | E-1051-93-183 | Staff | 1994 | Rate Base, Operating Income |
| PSI Energy, Inc. | Indiana | URC | 39584 | Consumer Counselor | 1994 | Rate Base, Operating Income, Alt. Regulation, Forecasts, Affiliated Interest |
| Arkla, a Division of NORAM Energy | Oklahoma | OCC | PUD-940000354 | Attorney General | 1994 | Cost Allocations, Rate Design |
| PSI Energy, Inc. | Indiana | URC | 39584-S2 | Consumer Counselor | 1994 | Merger Costs and Cost Savings, Non-Traditional Ratemaking |
| Transok, Inc. | Oklahoma | OCC | PUD-1342 | Staff | 1994 | Rate Base, Operating Income, Affiliated Interest, Allocations |
| Oklahoma Natural Gas Company | Oklahoma | OCC | PUD-940000477 | Attorney General | 1995 | Rate Base, Operating Income, Cost of Service, Rate Design |
| US West Communications | Washington | WUTC | UT-950200 | Attorney General/ TRACER | 1995 | Operating Income, Affiliate Interest, Service Quality |
| PSI Energy, Inc. | Indiana | URC | 40003 | Consumer Counselor | 1995 | Rate Base, Operating Income |
| Oklahoma Natural Gas Company | Oklahoma | OCC | PUD-880000598 | Attorney General | 1995 | Stand-by Tariff |
| GTE Hawaiian Telephone Co., Inc. | Hawaii | PUC | PUC 94-0298 | Consumer Advocate | 1996 | Rate Base, Operating Income, Affiliate Interest, Cost Allocations |
| Mid-American Energy Company | Iowa | ICC | APP-96-1 | Consumer Advocate | 1996 | Non-Traditional Ratemaking |
| Oklahoma Gas and Electric Company | Oklahoma | OCC | PUD-960000116 | Attorney General | 1996 | Rate Base, Operating Income, Rate Design, Non-Traditional Ratemaking |
| Southwest Gas Corporation | Arizona | ACC | U-1551-96-596 | Staff | 1997 | Operating Income, Affiliated Interest, Gas Supply |

Michael L. Brosch
Summary of Previously Filed Testimony

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|---|---|---|---|---|---|---|
| Utilicorp United - Missouri Public Service Division | Missouri | PSC | EO-97-144 | Staff | 1997 | Operating Income |
| US West Communications | Utah | PSC | 97-049-08 | Consumer Advocate | 1997 | Rate Base, Operating Income, Affiliate Interest, Cost Allocations |
| US West Communications | Washington | WUTC | UT-970766 | Attorney General | 1997 | Rate Base, Operating Income |
| Missouri Gas Energy | Missouri | PSC | GR 98-140 | Public Counsel | 1998 | Affiliated Interest |
| ONEOK | Oklahoma | OCC | PUD980000177 | Attorney General | 1998 | Gas Restructuring, rate Design, Unbundling |
| Nevada Power/Sierra Pacific Power Merger | Nevada | PSC | 98-7023 | Consumer Advocate | 1998 | Merger Savings, Rate Plan and Accounting |
| PacifiCorp / Utah Power | Utah | PSC | 97-035-1 | Consumer Advocate | 1998 | Affiliated Interest |
| MidAmerican Energy / CalEnergy Merger | Iowa | PUB | SPU-98-8 | Consumer Advocate | 1998 | Merger Savings, Rate Plan and Accounting |
| American Electric Power / Central and South West Merger | Oklahoma | OCC | 980000444 | Attorney General | 1998 | Merger Savings, Rate Plan and Accounting |
| ONEOK Gas Transportation | Oklahoma | OCC | 970000088 | Attorney General | 1998 | Cost of Service, Rate Design, Special Contract |
| U S West Communications | Washington | WUTC | UT-98048 | Attorney General | 1999 | Directory Imputation and Business Valuation |
| U S West / Qwest Merger | Iowa | PUB | SPU 99-27 | Consumer Advocate | 1999 | Merger Impacts, Service Quality and Accounting |
| U S West / Qwest Merger | Washington | WUTC | UT-991358 | Attorney General | 2000 | Merger Impacts, Service Quality and Accounting |
| U S West / Qwest Merger | Utah | PSC | 99-049-41 | Consumer Advocate | 2000 | Merger Impacts, Service Quality and Accounting |
| PacifiCorp / Utah Power | Utah | PSC | 99-035-10 | Consumer Advocate | 2000 | Affiliated Interest |
| Oklahoma Natural Gas, ONEOK Gas Transportation | Oklahoma | OCC | 980000683, 980000570, 990000166 | Attorney General | 2000 | Operating Income, Rate Base, Cost of Service, Rate Design, Special Contract |
| U S West Communications | New Mexico | PRC | 3008 | Staff | 2000 | Operating Income, Directory Imputation |
| U S West Communications | Arizona | ACC | T-0105B-99-0105 | Staff | 2000 | Operating Income, Rate Base, Directory Imputation |
| Northern Indiana Public Service Company | Indiana | IURC | 41746 | Consumer Counsel | 2001 | Operating Income, Rate Base, Affiliate Transactions |
| Nevada Power Company | Nevada | PUCN | 01-10001 | Attorney General-BCP | 2001 | Operating Income, Rate Base, Merger Costs, Affiliates |
| Sierra Pacific Power Company | Nevada | PUCN | 01-11030 | Attorney General-BCP | 2002 | Operating Income, Rate Base, Merger Costs, Affiliates |
| The Gas Company, Division of Citizens Communications | Hawaii | PUC | 00-0309 | Consumer Advocate | 2001 | Operating Income, Rate Base, Cost of Service, Rate Design |
| SBC Pacific Bell | California | PUC | I.01-09-002 R.01-09-001 | Office of Ratepayer Advocate | 2002 | Depreciation, Income Taxes and Affiliates |
| Midwest Energy, Inc. | Kansas | KCC | 02-MDWG-922-RTS | Agriculture Customers | 2002 | Rate Design, Cost of Capital |

Michael L. Brosch
Summary of Previously Filed Testimony

| | | | | | | |
|---|---|---|---|---|---|---|
| Qwest Communications – Dex Sale | Utah | PSC | 02-049-76 | Consumer Advocate | 2003 | Directory Publishing |
| Qwest Communications – Dex Sale | Washington | WUTC | UT-021120 | Attorney General | 2003 | Directory Publishing |
| Qwest Communications – Dex Sale | Arizona | ACC | T-0105B-02-0666 | Staff | 2003 | Directory Publishing |
| PSI Energy, Inc. | Indiana | IURC | 42359 | Consumer Counsel | 2003 | Operating Income, Rate Trackers, Cost of Service, Rate Design |
| Qwest Communications – Price Cap Review | Arizona | ACC | T-0105B-03-0454 | Staff | 2004 | Operating Income, Rate Base, Fair Value, Alternative Regulation |
| Verizon Northwest Corp | Washington | WUTC | UT-040788 | Public Counsel | 2004 | Directory Publishing, Rate Base, Operating Income |
| Citizens Gas & Coke Utility | Indiana | IURC | 42767 | Consumer Counsel | 2005 | Operating Income, Debt Service, Working Capital, Affiliate Transactions, Alternative Regulation |
| Hawaiian Electric Company | Hawaii | HPUC | 04-0113 | Consumer Advocate | 2005 | Operating Income, Rate Base, Cost of Service, Rate Design |
| Sprint/Nextel Corporation | Washington | WUTC | UT-051291 | Public Counsel | 2006 | Directory Publishing, Corporate Reorganization |
| Puget Sound Energy, Inc. | Washington | WUTC | UE-060266 and UG-060267 | Public Counsel | 2006 | Alternative Regulation |
| Hawaiian Electric Company | Hawaii | HPUC | 05-0146 | Consumer Advocate | 2006 | Community Benefits / Rate Discounts |
| Cascade Natural Gas Company | Washington | WUTC | UG-060259 | Public Counsel | 2006 | Alternative Regulation |
| Arizona Public Service Company | Arizona | ACC | E-01345A-05-0816 | Staff | 2006 | Cost of Service Allocations |

Backgrounder
United States Nuclear Regulatory Commission
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# Reactor License Renewal

## Introduction

Based on the Atomic Energy Act, the Nuclear Regulatory Commission (NRC) issues licenses for commercial power reactors to operate for up to 40 years and allows these licenses to be renewed for up to another 20 years. A 40-year license term was selected on the basis of economic and antitrust considerations, not technical limitations.

The decision whether to seek license renewal rests entirely with nuclear power plant owners, and typically is based on the plant's economic situation and whether it can meet NRC requirements. There are 104 reactors in the U.S. originally licensed to operate for 40 years. In 2009, the first operating licenses will expire for two reactors; 13 others will expire by 2015. To date, the NRC has approved license renewal for 44 reactors.

The NRC has established a license renewal process that can be completed in a reasonable period of time with clear requirements to assure safe plant operation for up to an additional 20 years of plant life.

## Background

In 1982, based on a widely attended workshop on nuclear power plant aging, the NRC established a comprehensive program for Nuclear Plant Aging Research. Based on the results of that research, a technical review group concluded that many aging phenomena are readily manageable and do not pose technical issues that would preclude life extension for nuclear power plants.

In 1991, the NRC published safety requirements for license renewal as 10 CFR Part 54 (Title 10 of the Code of Federal Regulations, Part 54). The NRC then undertook a demonstration program to apply the rule to pilot plants and develop experience to establish implementation guidance. To establish a scope of review, the rule defined age-related degradation unique to license renewal. However, during the demonstration program, the NRC found that many aging effects are dealt with adequately during the initial license period. In addition, the NRC found that the review did not allow sufficient credit for existing programs, particularly those under NRC's maintenance rule, which also helps manage plant aging phenomena.

As a result, in 1995, the NRC amended the license renewal rule. The amended Part 54 established a regulatory process that is more efficient, more stable and more predictable than the previous license renewal rule. In particular, Part 54 was clarified to focus on managing the adverse effects of aging. The rule changes were intended to ensure that important systems, structures and components will continue to perform their intended function during the 20-year period of extended operation.

NRC's responsibilities under the National Environmental Policy Act call for a review of the environmental impact of license renewal. In parallel with aging efforts, the NRC pursued a separate rulemaking, 10 CFR Part 51, to focus the scope of review of environmental issues.

## Renewal Process

The license renewal process proceeds along two tracks -- one for review of safety issues (Part 54) and another for environmental issues (Part 51). An applicant must provide NRC an evaluation that addresses the technical aspects of plant aging and describes the ways those effects will be managed. It must also prepare an evaluation of the potential impact on the environment if the plant operates for another 20 years. The NRC reviews the application and verifies the safety evaluations through inspections.

Public participation is an important part of the license renewal process. There are several opportunities for members of the public to question how aging will be managed during the period of extended operation. Information provided by the licensee is made available to the public in a variety of ways. Shortly after the NRC receives a renewal application, a public meeting is normally held near the nuclear power plant to provide the public information about the license renewal process and opportunities for public involvement, and to solicit input on the scope of NRC's environmental review. Additional public meetings are held by the NRC during the review of the renewal application, and NRC evaluations, findings and recommendations are published when completed.

All public meetings are posted on NRC's Web site, with key ones being announced in press releases and in the *Federal Register*. Concerns may be litigated in an adjudicatory hearing if any party that would be adversely affected requests a hearing. In addition, members of the public may petition the Commission for consideration of issues other than the management of the effects of aging during the period of extended operation of the plant.

A nuclear power plant licensee may apply to the NRC to renew its license as early as 20 years before expiration of its current license. There is no limit on how late a licensee may apply for license renewal. However, if the licensee submits a renewal application that is sufficient for the NRC's review at least five years before expiration of its current license and the agency is still reviewing the application at the end of the five years, the plant can continue to operate until the NRC completes its review. If a sufficient application is not submitted at least five years before and the current license expires before the review has been completed, the plant may have to cease operations until the renewal decision is made.

License renewal is expected to take about 30 months, including the time to conduct an adjudicatory hearing, if necessary, or 22 months without a hearing. In some cases the process is completed on a plant-specific schedule agreed upon with the applicant. Upon receipt of a license renewal application, the review is conducted, in general, according to the steps in the following table:

| Licensing Milestone | Months Elapsed |
|---|---|
| Receive renewal application | 0 |
| Publish notice of opportunity for hearing | 1.5 |
| Conduct public meeting on license renewal process and scope of environmental impact statement | 2.5 |
| Opportunity for hearing closes | 3.5 |
| Pose environmental questions to applicant | 5.5 |
| Pose safety questions to applicant | 6.0 |
| Issue draft environmental impact statement for comment | 11.0 |
| Conduct public meeting on draft environmental impact statement | 12.0 |
| Issue safety evaluation report, identifying open items | 13.0 |
| Issue final environmental impact statement | 18.0 |
| Issue safety evaluation report | 18.0 |
| Complete Advisory Committee on Reactor Safety Review | 20.0 |
| Make decision on application (without hearing) | 22.0 |
| Complete hearing process (if needed) | --- |
| Make decision on application (with hearing) | 30.0 |

## Environmental Reviews

Environmental protection regulations were revised in December 1996 to facilitate the environmental review for license renewal. Certain issues are evaluated generically for all plants, rather than separately in each plant's renewal application. The generic evaluation, NUREG-1437, "Generic Environmental Impact Statement for License Renewal of Nuclear Plants" (GEIS), assesses the scope and impact of environmental effects that would be associated with license renewal at any nuclear power plant site such as endangered species, impacts of cooling water systems on fish and shellfish, and ground water quality. A plant-specific supplement to the generic environmental impact statement is required for each application for license renewal.

The NRC performs plant-specific reviews of the environmental impacts of license renewal in accordance with the National Environmental Policy Act (NEPA) and the requirements of 10 CFR Part 51. The public meeting held near the nuclear power plant shortly after receipt of the application is to "scope out" or identify environmental issues specific to the plant for the license renewal action. The result is an NRC recommendation on whether the environmental impacts are so great that they preclude license renewal. This recommendation is presented in a draft plant-specific supplement to the GEIS which is published for comment and discussed at a separate public meeting. After consideration of comments on the draft, NRC prepares and publishes a final plant-specific supplement to the GEIS.

The NRC issued a standard review plan (NUREG-1555, Supplement No.1) which provides guidance on how the agency is to review the environmental portions of renewal applications. The NRC also issued Supplement 1 to Regulatory Guide 4.2, that identifies the format and content of environmental reports which must accompany license renewal applications.

## Safety Reviews

License renewal requirements for power reactors are based on two key principles:

1) The regulatory process is adequate to ensure that currently operating plants will continue to maintain adequate levels of safety during extended operation, with the possible exception of detrimental effects of aging on certain systems, structures and components, and a few other issues that may arise during the period of extended operation; and

2) Each plant's licensing basis is required to be maintained during the renewal term in the same manner and to the same extent as during the original licensing term.

An applicant must identify all plant systems, structures and components that are safety-related, or whose failure could affect safety-related functions, and that are relied on to demonstrate compliance with the NRC's regulations for fire protection, environmental qualification, pressurized thermal shock, anticipated transients without scram, and station blackout.

The applicant is then required to identify all structures and components within the scope of the rule that are "passive and long-lived." It must be demonstrated that the effects of aging will be managed in such a way that the intended functions of passive and long-lived structures and components will be maintained for the period of extended operation. Passive and long-lived structures and components include components such as the reactor vessel, reactor coolant system piping, steam generators, pressurizer, pump casings, and valve bodies.

The detrimental aging effects in "active" components are more readily detected and corrected by routine surveillance, performance indicators and maintenance. Surveillance and maintenance programs for active components are required throughout the original license term and will continue throughout the period of extended operation. Therefore, active components do not require additional review during the license renewal process. Active components include equipment such as motors, diesel generators, cooling fans, batteries, relays, and switches.

For some passive structures and components within the scope of the renewal evaluation, no additional action may be required where an applicant can demonstrate that the existing programs provide adequate aging management throughout the period of extended operation. However, if additional aging management activities are warranted for a structure or component within the scope of the rule, applicants will have the flexibility to determine appropriate actions. These activities could include, for example, adding new monitoring programs or increasing inspections.

License renewal applicants are also required to identify and update time-limited aging analyses. During the design phase for a plant, certain assumptions about the length of time the plant will be operated are incorporated into design calculations for several of the plant's systems, structures, and components. Under a renewed license, these calculations must be shown to be valid for the period of extended operation, or the affected systems, structures and components must be included in an appropriate aging management program.

The NRC developed guidance for implementation of the license renewal rule with input from interested stakeholders. A Generic Aging Lessons Learned (GALL) report (NUREG-1801) was prepared and made publicly available. The report documents the basis for determining when existing programs are adequate and when existing programs should be augmented for license renewal. The GALL report is referenced in the standard review plan for license renewal (NUREG-1800) as the basis for identifying those programs that warrant particular attention during NRC's review of a license renewal application.

The NRC also issued Regulatory Guide 1.188, which provides the format and content of the safety aspects of a license renewal application. It endorses a guideline prepared by the Nuclear Energy Institute as an acceptable method of implementing the license renewal rule. The NRC will continue to include changes to the guide and the standard review plan as generic renewal issues are resolved, as well as other changes resulting from lessons learned and process improvements identified during the review of renewal applications.

## Inspections

The NRC has established an inspection program for license renewal that verifies the information in the application and NRC's evaluation. The inspections sample the results of the process used by the licensee to identify those structures and components within the scope of license renewal, aging management programs and design analysis changes. Inspection results are documented in a publicly available report.

## Hearings

The Commission expects that hearings be conducted on an efficient and reliable schedule, while ensuring fair resolution of contested issues. In addition, there should be timely identification of any open generic policy issues for Commission decision and effective integration of the review of technical issues into the adjudicatory process.

The Commission amended its regulations concerning its rules of practice to make the NRC's hearing process more effective and efficient (*Federal Register* Vol. 69, page 2182, January 14, 2004). Hearing procedures are tailored to the differing types of licensing and regulatory activities the NRC conducts and will better focus limited resources of involved parties and the NRC.

## Industry Activities

The industry has submitted technical reports on particular license renewal topics for NRC approval. This approach, along with compilations of past aging research programs, established a foundation of technical information that licensees can use to evaluate the feasibility of license renewal and later reference in a license renewal application.

With regard to pressurized water reactors, the Babcock & Wilcox Owners Group, representing five operating B&W plants, has formulated a generic license renewal program. The B&W Owners Group has submitted generic license renewal reports on the reactor coolant system piping, the pressurizer, the reactor pressure vessel, and reactor vessel internals. The Westinghouse Owners Group also has a program for license renewal and has submitted technical reports on the aging management activities for the reactor coolant system supports, the pressurizer, certain piping, the containment structure, and the reactor vessel internals. The Boiling Water Reactor Owners Group has concentrated its efforts on reports related to the reactor vessel internals program.

Industry representatives participated in working groups and technical committees, coordinated by the Nuclear Energy Institute, to address generic technical and process issues. The resolution of the generic renewal issues and lessons learned during the review of renewal applications are documented and included in revisions of the guidance documents for implementing the license renewal rule.

## Status of License Renewal Applications

Some licensees have expressed interest in license renewal and have described their plans to submit license renewal applications. In anticipation of continued interest by licensees in submitting renewal applications in the coming years, and with increasing experience in reviewing license renewal applications, the NRC expects to make the renewal review process more efficient.

The status of pending planned applications as well as additional information on license renewal can be found at: http://www.nrc.gov/reactors/operating/licensing/renewal.html on the NRC web site.

See the table below for the current status of license renewal applications.

**Status of License Renewal Applications**

| Applicant | Plant Name & Units | Date Application Received by NRC | Date NRC Issued GEIS Supplement* | Date NRC Issued SER** | Date NRC Issued License |
|---|---|---|---|---|---|
| Baltimore Gas & Electric Co. | Calvert Cliffs 1 & 2 | April 1998 | November 1999 | November 1999 | March 2000 |
| Duke Energy | Oconee 1, 2, & 3 | July 1998 | February 2000 | February 2000 | May 2000 |
| Entergy Nuclear Operations | Arkansas Nuclear One 1 | February 2000 | April 2001 | April 2001 | June 2001 |
| Southern Nuclear Operating Co. | Edwin I. Hatch 1 & 2 | March 2000 | May 2001 | October 2001 | January 2002 |
| Florida Power & Light Co. | Turkey Point 3 & 4 | September 2000 | January 2002 | February 2002 | June 2002 |
| Virginia Electric & Power | Surry 1 & 2 North Anna 1 & 2 | May 2001 | December 2002 | November 2002 | March 2003 |
| Duke Energy | McGuire 1&2 Catawba 1 & 2 | June 2001 | December 2002 | January 2003 | December 2003 |
| Exelon | Peach Bottom 2&3 | July 2001 | January 2003 | February 2003 | May 2003 |
| Florida Power & Light Co. | St. Lucie 1 & 2 | November 2001 | May 2003 | July 2003 | October 2003 |
| Omaha Public Power District | Fort Calhoun | January 2002 | August 2003 | September 2003 | November 2003 |
| Carolina Pwr. & Light | Robinson 2 | June 2002 | December 2003 | January 2004 | April 2004 |
| Rochester Gas & Elec. Corp. | Ginna | August 2002 | January 2004 | March 2004 | May 2004 |
| SCE&G | Summer | August 2002 | February 2004 | January 2004 | April 2004 |

| **Applicant** | **Plant Name & Units** | **Date Application Received by NRC** | **Date NRC Issued GEIS Supplement*** | **Date NRC Issued SER**** | **Date NRC Issued License** |
|---|---|---|---|---|---|
| Exelon | Dresden 2 & 3 Quad Cities 1 & 2 | January 2003 | June 2004 | July 2004 | October 2004 |
| Southern Nuclear Operating Co. | Farley 1&2 | September 2003 | March 2005 | March 2005 | May 2005 |
| Entergy Nuclear Operations | Arkansas Nuclear One 2 | October 2003 | April 2005 | April 2005 | June 2005 |
| Indiana & Michigan Power Co. | D.C. Cook 1&2 | November 2003 | April 2005 | May 2005 | August 2005 |
| Tennessee Valley Authority | Browns Ferry 1, 2 & 3 *** | January 2004 | June 2005 | January 2006 | May 2006 |
| Dominion Nuclear Connecticut | Millstone 2&3 | January 2004 | July 2005 | August 2005 | November 2005 |
| Nuclear Management Co. | Point Beach 1 & 2 | February 2004 | August 2005 | October 2005 | December 2005 |
| Constellation Energy | Nine Mile Point 1 & 2 *** | May 2004 | May 2006 | June 2006 | |
| Carolina Power & Light | Brunswick 1 & 2 | October 2004 | April 2006 | March 2006 | June 2006 |
| Nuclear Management Co. | Monticello | March 2005 | September 2006 | July 2006 | |
| Nuclear Management Co. | Palisades *** | March 2005 | October 2006 | September 2006 | |
| AmerGen Energy Co. | Oyster Creek | July 2005 | | | |

| **Applicant** | **Plant Name & Units** | **Date Application Received by NRC** | **Date NRC Issued GEIS Supplement*** | **Date NRC Issued SER**** | **Date NRC Issued License** |
|---|---|---|---|---|---|
| Entergy Nuclear Operations | Pilgrim | January 2006 | | | |
| Entergy Nuclear Operations | Vermont Yankee | January 2006 | | | |
| Entergy Nuclear Operations | FitzPatrick | August 2006 | | | |
| PPL Susquehanna LLC | Susquehanna | September 2006 | | | |
| Wolf Creek Nuclear Operating Corp. | Wolf Creek | October 2006 | | | |

*    Plant-specific supplement to the Generic Environmental Impact Statement
**   Safety Evaluation Report
*** Plant-specific review schedule

October 2006

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Chair
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SHEILA LUMPE
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# *Missouri Public Service Commission*

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DANA K. JOYCE
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March 18, 2003

The Honorable Magalie R. Salas, Secretary
Federal Energy Regulatory Commission
888 First Street, N.E.
Washington D.C. 20426

Re: Ameren Energy Generating Co. and Union Electric Co. d/b/a AmerenUE, Docket No. EC03-53-000 -- Comments of the Missouri Public Service Commission Regarding the Application to Transfer Generating Assets from Ameren Energy Generating Co. to AmerenUE

Dear Ms. Salas:

Union Electric Company d/b/a AmerenUE ("AmerenUE") has asked the Missouri Public Service Commission ("Missouri Commission") to submit a letter to the Federal Energy Regulatory Commission ("FERC") requesting that the FERC expeditiously approve the February 5, 2003 Application of Ameren Energy Generating Company ("AEG") and AmerenUE (collectively, "Applicants") filed in Docket No. EC03-53-000 for all authorizations and approvals necessary, under section 203 of the Federal Power Act ("FPA"), 16 U.S.C. § 824b, for AEG to sell and transfer, and AmerenUE to purchase and accept, certain generation assets now owned by AEG. This letter is the Missouri Commission's response to AmerenUE's request.

The Missouri Commission agrees with the Applicants that the proposed transaction would address certain provisions of a Stipulation and Agreement ("Stipulation") that was approved by the Missouri Commission on July 25, 2002. Specifically, the transaction would address the term of the Stipulation that says AmerenUE is to make infrastructure investments to add 700 MW of generating capacity over the period of an agreed to rate moratorium through June 30, 2006. [Stipulation, Section 4]. The Stipulation allows for this obligation to be met through the purchase of generating facilities from an affiliate at net book value but the Stipulation does not require that the additional generating capacity obligation be satisfied through the purchase of capacity from an affiliate to the exclusion of other available options. At the time the costs from this transaction are considered for ratemaking purposes, AmerenUE will be responsible to demonstrate that this transaction was prudent and reasonable in light of other available options.

Neither the Commission nor its Staff have conducted an evaluation of the prudence of the present course of action taken by AmerenUE, which evaluation would include an examination of the options available to AmerenUE to meet this need. Missouri statutes do not require the pre-approval by the Missouri Commission of a utility's acquisition or construction of generating assets. Instead, at the time the costs of such acquisitions are sought to be recovered in rates and the investment is sought to be included in rate base for Missouri bundled retail customers, the Missouri Commission will make a determination whether such costs were prudently and reasonably incurred by the utility, including whether such an acquisition was a prudent long-run cost alternative for meeting the needs of Missouri bundled retail customers.[1]

AmerenUE projects a need for 543 megawatts of generation capacity to meet its generation adequacy requirement[2] for the summer of 2003, and the Application would transfer 548 megawatts of combustion turbine capacity to meet that need. Because the Missouri Commission is concerned that the FERC might place some incorrect interpretation on the Missouri Commission's not intervening in FERC Docket No. EC03-53-000, the Missouri Commission states that it has not filed an intervention as it expects that this transfer of assets will come before the Missouri Commission in a state ratemaking proceeding at a future date. Thus, even if the Missouri Commission were to intervene, it would not participate in any manner that might indicate prejudgment of the matters that later will be decided by the Missouri Commission, if the FERC approves the February 5, 2003 Application.

The Missouri Commission assures the FERC that the interests of bundled retail customers in Missouri will be protected in a Missouri Commission proceeding, and on that basis requests that the FERC timely consider the AmerenUE and AEG Application and states further that it does not object to FERC approval of that Application. The Missouri Commission further states that it is not seeking to comment in any manner on the protests filed by various entities in the instant proceeding.

Respectively submitted,

**/s/ Kelvin L. Simmons**

Kelvin L. Simmons

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[1] In 1999, certain Missouri investor-owned electric utilities, including Union Electric Company, filed an application requesting that the Missouri Commission rescind its electric resource planning rules (4 CSR 240-22). As a result of that filing, a Unanimous Stipulation And Agreement was reached and approved by the Missouri Commission, whereby the Missouri investor-owned electric utilities were granted variances from the Commission's electric resource planning rules. Instead of following the detailed procedures set out in those rules, the Missouri investor-owned electric utilities meet with the Missouri Commission Staff and others every six months to provide an update on their resource plans. These utilities also submit to the Manager of the Missouri Commission's Energy Department, a letter and documents in support of specific resource acquisitions. Neither the electric resource planning rules, the bi-annual meetings nor the letters and documents in support of specific resource acquisitions require or constitute pre-approval by the Missouri Commission for purposes of setting utility rates. (If the Missouri Commission grants a utility a certificate of convenience and necessity to serve a specified service territory, the utility does not need subsequent Commission authorization to construct generation, transmission or distribution facilities within that certificated service territory.)

[2] AmerenUE's generation adequacy requirement is to meet the reliability reserve requirements of the Mid-American Interconnected Network, Inc, of which AmerenUE is a member.

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DANA K. JOYCE
General Counsel

June 3, 2003

The Honorable Magalie R. Salas, Secretary
Federal Energy Regulatory Commission
888 First Street, N.E.
Washington, D.C. 20426

Re: Ameren Energy Generating Co. and Union Electric Co. d/b/a AmerenUE, Docket No. EC03-53-000 - Additional Comments of the Missouri Public Service Commission

Dear Ms. Salas

By letter dated March 18, 2003, the Missouri Public Service Commission ("Missouri Commission") submitted comments to the Federal Energy Regulatory Commission ("FERC") on the February 5, 2003 Application of Ameren Energy Generating Company ("AEG") and Union Electric Company d/b/a ("AmerenUE") (collectively, "Applicants"), filed in FERC Docket No. EC03-53-000 ("February 5 Application"). A copy of the March 18th letter is attached. By order issued May 5, 2003 in Docket No. EC03-53, the FERC set the February 5 Application for hearing to examine its possible effects on competition.[1]

As recognized in the May 5th Order (at ¶¶13, 47), the option for AmerenUE to purchase generating plant from AEG was provided for in the rate case settlement and stipulation that was approved by the Missouri Commission on July 25, 2002 ("Settlement"). Prior to the Settlement, AmerenUE had met on several occasions with Missouri Commission staff to discuss AmerenUE's purchase of generating units from AEG, more particularly, purchase of the Columbia[2] and Pinckneyville units. The Missouri Commission believes that infrastructure improvement was a

[1] Ameren Energy Generating Co. and Union Electric Co. d/b/a AmerenUE, 103 FERC ¶ 61,128, at P 35 (2003) ("May 5 Order").
[2] Subsequent to those Staff discussions, AmerenUE discussed with MoPSC Staff the substitution of the Kinmundy plant for the Columbia plant due to issues that made transfer of the Columbia facility less feasible.

Schedule MLB-4

fundamental component of the Settlement. AmerenUE's ability to purchase the Columbia and Pinckneyville generating units from AEG was a known and viable option for meeting capacity infrastructure needs at the time of the Settlement.

The Missouri Commission is mindful of FERC's policy considerations set forth in the Cinergy order.[3] The Missouri Commission is also mindful that the stipulation approved by the Missouri Commission became effective prior to FERC's reference in Cinergy to a prospective methodology. The Missouri Commission requests that the FERC recognize AmerenUE's need to acquire secure supplies, just as it recognized the need of PSI in the Cinergy case.

The Missouri Commission prefers the surety and reliability of dedicated assets to meet Missouri load requirements to protect Missouri consumers from price spikes and curtailment issues. AmerenUE's application to purchase the generating units is consistent with this preference and with the rate case settlement and stipulation approved by the Missouri Commission, and the prudency of this transaction will be reviewed by the Missouri Commission. AmerenUE agrees that the Missouri Commission has the authority to fully analyze the prudency of this proposed transaction, including, but not limited to, the timing of the purchase, the amount of the purchase, the need for the purchase, and the appropriateness of the purchase in light of other options, including purchase on the market or acquisition of other assets. In exercising this authority, the Missouri Commission is confident that it can protect the interests of ratepayers and shareholders.

The Missouri Commission requests, therefore, that the FERC expeditiously reconsider its May 5 Order in which it set this matter on a hearing track. Further, the Missouri Commission asks that FERC not render a decision or establish a policy that promotes a competitive market in exchange for Missouri consumers being exposed to greater upward price volatility and a reduced reliability of supply.

Respectfully submitted,

Kelvin L. Simmons
Chair

Attachment

cc: Hon. Connie Murray
Hon. Steve Gaw
Hon. Bryan Forbis
Hon. Robert Clayton III
Steven R. Sullivan, Vice-President Regulatory Policy,
General Counsel and Secretary, Ameren Services, Co.

[3] See, Cinergy Services, Inc., 102 FERC ¶ 61,128 (2003) ("Cinergy").