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Witness: Steven C. Carver
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Case No. ER-2007-0002
Date Testimony Prepared: December 15, 2006

BEFORE THE PUBLIC SERVICE COMMISSION

STATE OF MISSOURI

DIRECT TESTIMONY

OF

STEVEN C. CARVER

FILED[3]
APR 2 5 2007
Missouri Public Service Commission

ON BEHALF OF

THE STATE OF MISSOURI

NP

State Exhibit No. 506NP
Case No(s). ER-2007-0002
Date 3/29/07 Rptr PF

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF MISSOURI

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

AFFIDAVIT OF STEVEN C. CARVER

STATE OF MISSOURI)
) ss
COUNTY OF JACKSON)

Steven C. Carver, 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.

Steven C. Carver

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

Notary

NOTARY PUBLIC NOTARY SEAL STATE OF MISSOURI

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

TABLE OF CONTENTS

DIRECT TESTIMONY OF
STEVEN C. CARVER

Attachments

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF MISSOURI
DIRECT TESTIMONY OF STEVEN C. CARVER
ON BEHALF OF THE STATE OF MISSOURI
CASE NO. ER-2007-0002

Q. Please state your name and business address.

A. My name is Steven C. Carver. My business address is 740 NW 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., which specializes in providing consulting services for clients who actively participate in the process surrounding the regulation of public utility companies. Our work includes the review of utility rate applications, as well as the performance of special investigations and analyses related to utility operations and ratemaking issues.

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

A. Utilitech was retained by the State of Missouri ("State") to assist in the review of and to respond to the revenue requirement filed by the Union Electric Company d/b/a AmerenUE (hereinafter "AmerenUE", "UE" or "Company") and to file testimony with this Commission regarding the results of our review.

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

A. Generally, my responsibilities in this docket encompass the review and evaluation of various elements of rate base and operating income included within the Company's overall revenue requirement. As a result, I address various adjustments to rate base and operating income, as identified on the earlier table of contents, as well as introduce the State's proposed capital structure (Schedule D) sponsored by State witness Dr. J. Randall Woolridge. The additional ratemaking adjustments, which I do not sponsor, are separately addressed in the direct testimony of State witness Michael Brosch. The revenue requirement effect of the various State sponsored adjustments and recommendations are reflected within the State Joint Accounting Schedules.

Q. Did scope of work requested by the State include both the electric and gas rate increases sought by AmerenUE?

A. No. Utilitech was retained by the State to review and evaluate the rate increase proposed by the Company for its Missouri electric operations.

Q. Have you previously testified before this Commission in proceedings that involved AmerenUE?

A. Yes. I have prepared and presented revenue requirement recommendations in several prior proceedings that involved Union Electric Company, while I was employed by this Commission. I have filed testimony in three of the Company's previous Missouri rate cases (Case Nos. ER-82-52, ER-83-163 and ER-84-168/ EO-85-17) dating back to 1982.

EDUCATION AND EXPERIENCE

Q. What is your educational background?

A. I graduated from State Fair Community College, where I received an Associate of Arts Degree with an emphasis in Accounting. I also graduated from Central Missouri State University with a Bachelor of Science Degree in Business Administration, majoring in Accounting.

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

A. From 1977 to 1987, I was employed by the Missouri Public Service Commission ("MoPSC") in various professional auditing positions associated with the regulation of public utilities. In April 1983, I was promoted by the Missouri Commissioners to the position of Chief Accountant and assumed overall management and policy responsibilities for the Accounting Department. I provided guidance and assistance in the technical development of Staff issues in major rate cases and coordinated the general audit and administrative activities of the Department.

I commenced employment with the firm in June 1987. During my employment with Utilitech, I have been associated with various regulatory projects on behalf of clients in the States of Arizona, California, Florida, Hawaii, Kansas, Illinois, Iowa, Indiana, Mississippi, Missouri, Nevada, New Mexico, New York, Oklahoma, Pennsylvania, Texas, Utah, Washington, West Virginia and Wyoming. I have conducted revenue requirement analyses and special studies involving various regulated industries (i.e., electric, gas, telephone and water). Since joining the firm, I have occasionally appeared as an expert witness before the MoPSC on behalf of various clients, including the

Commission Staff. Additional information regarding my professional experience and qualifications are summarized in Schedules SCC-1 and SCC-2.

EXECUTIVE SUMMARY

Q. What is the overall revenue requirement quantified by the State for the Company's Missouri retail operations?

A. Based on a historical test year ended June 30, 2006, with a true-up through January 1, 2007,[1] the Company has quantified an overall revenue deficiency of about $375 million.[2] In comparison, the State has assembled a revenue requirement recommendation for UE's electric operations, based on an internally consistent test year approach, supporting an overall revenue decrease of approximately $53 million. A series of accounting schedules supporting the State's recommended adjustments are set forth in the State Joint Accounting Schedules, which are bound separately.

Q. Please describe the State's approach to quantifying revenue requirement in this proceeding.

A. The State Joint Accounting Schedules use UE's "prefiled" amounts (as revised on September 29, 2006) for rate base, revenues and expenses as a starting point. The Company's proposed amounts were then adjusted to reflect the impact of the various adjustments to rate base and operating income as well as the capital cost recommendation sponsored by State witnesses.

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[1] By order issued September 12, 2006, in the pending docket, the Commission adopted the test year and true-up periods as agreed to by the parties.

[2] See UE Schedule GSW-E37, appended to the Supplemental Direct Testimony of Gary S. Weiss , dated September 29, 2006.

Q. Why were UE's "prefiled" amounts used as the starting point for the State Joint Accounting Schedules?

A. By starting with the Company's proposed amounts, each ratemaking adjustment proposed by State witnesses represents a reconciling difference, positive or negative, between the overall revenue requirement recommendations of the State and AmerenUE. In fact, State Schedule E represents a reconciliation of the individual revenue requirement differences between the Company and the State. While the same overall revenue requirement could have been quantified using unadjusted test year rate base and operating income amounts as the starting point, the approach used by the State serves to streamline the presentation of issues by focusing attention on the specific areas at issue.

Q. The various schedules attached to the Supplemental Direct Testimony of Company witness Weiss, which support the overall rate increase sought by AmerenUE, identify a number of adjustments to both rate base and operating income. If the Company proposed a specific adjustment that was not contested by a State witness, does that necessarily mean that the State concurs with each such adjustment?

A. No, not necessarily. During the course of a rate case proceeding, numerous adjustments and transactions may be reviewed as part of the process of evaluating a utility's overall revenue deficiency. While is it true that the State's direct testimony will address various areas of known disagreement with the Company's prefiled position, the absence of an adjustment in a particular area or to a specific component of the utility's revenue requirement does not indicate concurrence, but rather an indication that the State chose not to oppose a particular cost element or offer an alternative position.

Q. How are the State Joint Accounting Schedules organized?

A. Within the joint accounting schedules, which have been separately bound for ease of reference, the components of the State's proposed revenue requirement calculation appear on Schedule A, Change in Gross Revenue Requirement. The State's proposed rate base amount is brought forward from Schedule B, Summary of Jurisdictional Rate Base. Similarly, the State's adjusted net operating income recommendation is brought forward from Schedule C, Summary of Operating Income. The components of the State's cost of capital recommendation (i.e., rate of return) are detailed on Schedule D, Capital Structure & Costs. The development of the gross revenue conversion factor used to convert the net operating income deficiency (or excess) on Schedule A into the appropriate revenue requirement amount is set forth on Schedule A-1.

The various State recommended adjustments to rate base and operating income are supported by individual schedules, also contained within the joint accounting schedules. The witness sponsoring each adjustment and schedule comprising the State's overall revenue requirement recommendation is identified in the upper left-hand corner thereof and listed on the schedule index located at the front of the joint accounting schedules.

Q. How will you identify and refer to the individual accounting adjustments?

A. Both rate base and operating income adjustments have been numbered sequentially, but separately, beginning with the number "one". In order to distinguish the first rate base adjustment from the first operating income adjustment, the adjustment number is preceded by a reference to the schedule on which the adjustment was posted. For example, the posting schedule for the rate base adjustments is Schedule B. So, the first rate base adjustment would then be referenced as Schedule (or Adjustment) B-1. Similarly, the first operating income adjustment would be identified as Schedule (or Adjustment) C-1, since Schedule C is the posting schedule for the income statement adjustments. For purposes of testimony presentation in this proceeding, Mr. Brosch and I may use the words "schedule" and "adjustment" interchangeably when referring to the individual adjustments proposed by the State.

Q. Do the joint accounting schedules provide calculation detail supporting each State adjustment?

A. Generally, yes. The joint accounting schedules contain individual adjustment "schedules" that provide support for the quantification of each test year adjustment proposed by the Company, with footnote references to additional workpapers or other supporting documentation. Since virtually all information relied upon by the State in developing these adjustments was supplied by AmerenUE in response to written discovery, the adjustment schedules will often refer to relevant data sources already in the Company's possession, representing the primary support for the State adjustments affecting overall revenue requirement.

Q. Please describe how the remainder of your testimony is organized.

A. The remainder of my testimony is arranged by topical section, following the table index presented previously. This index identifies the specific areas I address in testimony and references the testimony pages as well as any related adjustment or schedule number located in the joint accounting schedules.

TEST YEAR

Q. Please briefly describe the test year approach used in this proceeding.

A. Paragraph 4 of the Order Adopting Procedural Schedule and Test Year ("Procedural Order"), issued by the Commission on September 12, 2006, specified that the test year for purposes of this case "shall be the year ending June 30, 2006, with a true-up through January 1, 2007." In general terms, a test year used for determining actual and pro forma rate base, operating revenues, expenses and operating income is a relatively recent twelve month period (i.e., June 2006) and adjusted for changes that are fixed, known and measurable for ratemaking purposes through a specified date (i.e., January 1, 2007) following the end of the test year. In addition, this Commission has typically recognized various end-of-period, annualization and normalization adjustments recognizing changes that occur during and subsequent to the test year in order to set rates on ongoing investment and cost levels.

Q. How does the approach employed by the State to quantify adjustments to test year rate base and operating income compare to the requirements of the Commission's Procedural Order?

A. In quantifying its revenue requirement recommendation, the various ratemaking adjustments proposed by the State are consistent with the Commission's Procedural

Order and serve to enhance the balance of the various elements of the ratemaking process, resulting in improved consistency in applying the overall test year approach.

Q. When you refer to improving the consistency in applying the Commission's test year approach, is it your intent to imply that each element of the ratemaking equation is developed in an identical manner?

A. No. In the ratemaking process, it is neither possible nor desirable to employ a stringent or mechanical method or approach to quantify each element of the ratemaking equation. Because the overall revenue requirement is comprised of various dissimilar elements, the technique employed to determine the ongoing level of revenues and expenses must be unique to the facts and circumstances underlying each element. Rather, it was my intent to indicate that the test year approach, as set forth in the Commission's Procedural Order, should be balanced and consistently applied to the various ratemaking elements, such that the resulting revenue requirement contains minimal quantification distortions.

Q. Why is the selection and balanced adjustment of a test year important in the determination of just and reasonable utility rates?

A. The ratemaking equation commonly employed by this Commission, and other regulatory agencies, compares a required return on rate base to the investment return generated by adjusted test year operating results. If the return indicated by the adjusted operating results (i.e., adjusted test year operating income and rate base) is deficient, an increase in revenues is required to provide the utility an opportunity to earn a "reasonable" return on its investment. Conversely, an excessive return would support a reduction in utility revenues and rates.

For the ratemaking equation to function properly, the components comprising the equation (i.e., rate base, revenues, expenses and rate of return) must be reasonably representative of ongoing levels, internally consistent and comparable – within the context of test period parameters. To the extent that these components are not properly synchronized, a utility may not have the opportunity to earn its authorized return or, alternatively, may have the opportunity to earn in excess of the return authorized. By synchronizing or maintaining the comparability of revenues, expenses and investment, the integrity of the test year can be maintained with the reasonable expectation that the resulting rates will not significantly misstate the ongoing cost of providing utility service.

Consequently, it is critical that the ratemaking process properly synchronize only those known and measurable changes which occur during the test year or within a reasonable period subsequent thereto, rather than establish utility rates on inappropriate factors or inconsistent post-test year events. In this manner, regulators can best be assured that rates are reasonably based on ongoing cost levels.

Q. Could you explain the concept of fixed, known and measurable changes, as typically used in the ratemaking process?

A. Yes. In general terms, the recognition of changes or adjustments to test year rate base and operating income should be consistently applied and limited to items that are fixed, known and measurable for ratemaking purposes. In my opinion, the following definition or explanation of the "fixed, known and measurable" concept, as commonly applied in utility ratemaking, is consistent with the Procedural Order:

> **Fixed, known and measurable changes** – transactions or events that are:
> (a) Fixed in time. A qualifying transaction or event must be "fixed" within the test year or within the specified period following the test year – or by January 1, 2007.
> (b) Known to occur. The transaction or event must be "known" to exist, in contrast with possible, uncertain or speculative changes.
> (c) Measurable in amount. The financial effect of the transaction or event can be "measured" or accurately quantified.

In this context, a transaction or event should only be considered fixed, known and measurable if it has been agreed to by contract or commitment, can be verified to have occurred within the specified time period, and can be quantified employing actual data.

It is not uncommon for regulatory commissions to recognize or annualize transactions occurring within, or subsequent to, the historical test period for verifiable, yet balanced, changes which will impact a utility's future earnings. However, it is also true that parties often differ on whether offsetting factors have been appropriately considered and how far outside the test year it may be appropriate to reach for changes. In my opinion, the recognition of fixed, known and measurable changes must be reasonably balanced or matched with offsetting factors. Otherwise, a distorted view of the cost of service will lead to improper rate adjustments. A consistent matching of both price and quantity changes is necessary to achieve this balance, particularly when volume changes, during or subsequent to the test year, offset price level increases.

Q. Please continue.

A. The fixed, known and measurable concept applies to all revenues, expenses and operating income items, unless the Procedural Order clearly specifies a separate cut-off date or variance. For example, an announced 1¢ postal rate increase effective January 1, 2007, would fall within the fixed, known and measurable or true-up period following the test year, as specified by the Commission. Presuming the availability of the data required to accurately quantify the annual pro forma impact of that increase on postage expense, an adjustment to annualize this "known" price change would be reasonable, all else remaining equal.

Instead, assume that the 1¢ postal rate increase was effective April 1, 2007. While this increase might be known and might be measurable, it clearly falls outside the true-up period specified in the Procedural Order. As a result, the April 2007 postal increase would not be eligible for annualization purposes.

Q. Based on your regulatory experience, is it reasonable to expect that changes occurring subsequent to a rate case test year will automatically put upward pressure on the cost of providing utility service?

A. No. It may be anticipated that the passage of time may result in increasing expenses (and investments), during periods of even modest inflation. As a result, the recognition of various revenue/ expense annualization and/ or normalization adjustments might be expected to consistently yield higher revenue requirements. However, revenue trends, productivity gains and reductions in certain operating expenses may offset the presumption of a generally increasing cost of service. Favorable and unfavorable revenue requirement influences can offset one another for many years, explaining how many utilities have avoided base rate increases for extended periods of time.

<u>All</u> components of the ratemaking equation change over time. It is only by consistently analyzing the major cost of service components that a determination can be made as to whether the overall revenue requirement has changed materially. The key issue is whether revenues are growing faster or slower than the overall costs necessary to support those revenues.

<u>RATE BASE UPDATE</u>

Q. Please describe State Adjustment B-1.

A. In quantifying the revenue requirement that accompanied the Company's supplemental filing on September 29, 2006,[3] AmerenUE generally started with a June 30, 2006, valuation of the major rate base components and then recognized certain adjustments and post-test year changes to plant in service and the accumulated depreciation reserve through December 2006. However, the Company's supplemental filing does not reflect estimated balances for plant in service, accumulated depreciation reserve and accumulated deferred income tax reserve at December 31, 2006. Although the Commission's Procedural Order specifies a time table for conducting a true-up through January 1, 2007, State Adjustment B-1 reflects a partial true-up of the key elements of rate base to reflect estimated balances for plant in service and the accumulated

[3] See schedules attached to the Supplemental Direct Testimony of Company witness Gary S. Weiss, dated September 29, 2006.

depreciation reserve at calendar year-end and the actual balances for the accumulated deferred income tax reserve as of October 2006. Further changes in the balances for plant in service, accumulated depreciation reserve and accumulated deferred income tax reserve through December 31, 2006, will be the subject of the true-up phase of this proceeding.

Q. Why is this adjustment necessary?

A. There are several known deficiencies in the Company's supplemental filing, which should be identified now rather than waiting until the true-up takes place. First, Company witness Weiss has specifically excluded all plant additions related to new business during the period July through December 2006. The rationale for this exclusion is premised on the fact that such new business additions will generate additional revenues. Since the Company has not proposed to adjust operating income to reflect said new business, the Company has simply excluded post-test year new business plant additions from rate base.[4] While the test year testimony section discusses the importance of the test year matching concept, the State recommends that it is more appropriate to quantify overall revenue requirement by recognizing new business revenue and margins, related operating expenses, if any, as well as all revenue producing new plant placed in service during the test year and through December 2006.

Second, the Company's proposed rate base does not recognize anticipated growth in the accumulated depreciation reserve and the accumulated deferred income tax reserve ("ADIT Reserve") in a manner similar to plant in service. Rather than include in rate

[4] Supplemental Direct Testimony of Company witness Weiss, .p. 8.

base 100% of the expected growth in these reserves associated with embedded plant and plant additions through December 2006, the Company has only recognized a portion of the growth in the depreciation reserve and has not proposed any change in the ADIT Reserve subsequent to June 2006.[5]

This State adjustment is necessary in order to convey the State's expectation that plant in service, accumulated deprecation reserve and ADIT reserve will be consistently updated through January 1, 2007, consistent with the true-up date set forth in the Commission's Procedural Order.

DEFERRED INCOME TAX RESERVE ADJUSTMENT

Q. Please describe State Adjustment B-2.

A. State Adjustment B-2 removes from rate base the ADIT Reserve balances associated with certain transactions that are not otherwise recognized in rate base for purposes of this rate case. For example, the ADIT Reserve balance (i.e., a net reduction to rate base) includes certain debit balances associated with pension (FAS87) and other postretirement retirement benefit (FAS106) transactions. Because neither the Company nor the State have proposed to recognize a rate base offset for any liability balances related to these items, the debit deferred income tax reserve items should also be excluded from the quantification of rate base. Otherwise, it would be wholly inconsistent and inappropriate to allow the debit deferred income tax reserves to increase rate base, and overall revenue requirement, while ignoring any related or matching liabilities that should be recognized

[5] See UE Schedules GSW-E21-1 (depreciation reserve), GSW-E27 (ADIT reserves) and GSW-E36 (jurisdictional rate base), as appended to Mr. Weiss' Supplemental Direct Testimony.

as a rate base offset. In other words, if the Company's liabilities are to be excluded from rate base, I believe that the companion deferred income tax reserves should be similarly excluded.

Q. Could you briefly outline the rate base concept?

A. Yes. Rate base is commonly viewed as being comprised of net utility asset investments used to provide regulated service to ratepayers – specifically, assets that have not yet been recovered from ratepayers. When utility investors provide the necessary funds to support these company investments, those amounts are generally included in rate base to allow the investors a return to which they are entitled. Similarly, funds advanced, reimbursed, or otherwise paid for by ratepayers are properly excludable from rate base. Matching is an important concept in determining the investment in rate base on which the utility should be allowed to earn a return in establishing utility rates.

The valuation date for plant in service to be included in rate base is typically "matched" with a common valuation date for the related accumulated depreciation reserve. For a typical utility, both plant in service and the depreciation reserve grow over time. By matching the valuation of plant in service with the depreciation reserve (i.e., specific point in time balances, test year averages, etc.), the quantification of rate base is balanced and equitable for both ratepayers and the utility. With respect to these debit deferred income tax reserves that are the subject of State Adjustment B-2, equity is achieved by their exclusion from rate base.

VEGETATION MANAGEMENT

Q. Please describe State Adjustment C-11.

A. During the test year ended June 30, 2006, AmerenUE has proposed to include about ** [redacted]** for tree trimming work in electric operations and maintenance (O&M) expense.[6] In response to Data Request AG/UTI-37, the Company provided copies of correspondence with the Commission Staff documenting an early 2005 agreement to achieve a four year urban and six year rural tree trimming cycle that provided for elimination of all backlog work by December 2008. According to this agreement, AmerenUE anticipated that annual tree trimming expenditures would be required for the next several years at or near $30 million.

The new vegetation management programs recommended by AmerenUE represent a 50% increase above and beyond the recently implemented trimming cycle program. State Adjustment C-11 has the effect of limiting the annual expenditures for the existing tree trimming program to $30 million and allows recovery of the $15 million cost of AmerenUE's new vegetation programs. Because of the challenges that have arisen due to the July and December 2006 storms, AmerenUE should be required to demonstrate its compliance with the 2005 Staff agreement by showing that it has, in fact, spent the $30 million annual allowance for the intended purpose – before the Commission allows additional new program costs to be charged to ratepayers

[6] UE Workpaper GSW-WP-E1126, supplemental direct testimony.

Q. Do you have any information regarding the status of the Company's work to achieve the four year urban and six year rural tree trimming cycle and eliminate all backlog work by December 2008?

A. According to the two quarterly reports AmerenUE provided to the Commission Staff in 2006, it appears that the Company's efforts were reasonably on track as of July 1, 2006.[7] However, I am unaware of any updates to this information that address the specific impact of the July and December 2006 storms on the status of this plan subsequent to June 2006.

Q. Beginning on page 4 of his Supplemental Direct Testimony, Mr. Zdellar proposes to expand its vegetation management to incorporate several new programs, in addition to the existing commitment to shorten its tree trimming cycles to four years for urban circuits and six years for rural circuits. According to Mr. Zdellar, AmerenUE has estimated that these new vegetation management programs will cost an incremental $15 million per year. Have you reviewed this testimony?

A. Yes. Mr. Zdellar states that the Company currently budgets $30 million per year for normal tree trimming and vegetation management and that the $15 million requested for the new vegetation programs represent additional, incremental work.[8] As recently as January 2005, AmerenUE committed to shorten its trimming cycles to four years (urban) and six years (rural), with completion by December 2008. At the time of the July 2006 storms, AmerenUE has indicated that it was on schedule to meet this commitment.[9] The

[7] AmerenUE response to AG/UTI-40

[8] Zdellar Supplemental Direct Testimony, p. 5.

[9] AmerenUE response to AG/UTI-46.

new programs, now proposed by Mr. Zdellar to further expand AmerenUE's vegetation management effort, are summarized below:[10]

1. Expand tree removal program to target problematic trees located on private property (i.e., off AmerenUE rights-of-way and easements); significantly expand right-of-way removal program.

2. Broaden clearance requirements, focusing initially on the backbone sections of the feeder (from the substation to the first protective device), by increasing side clearance, overhang removal, and tree crown reduction.

3. As trim cycle length reductions are completed, enhance system reliability by selectively reducing feeder cycle lengths (e.g., from a four year cycle to a three year cycle).

4. Increase current municipal tree replacement program more than fourfold, targeting trees for removal and/or replacement in order to reduce the risk of future potential outages.

Q. Is the State contesting the need for or the estimated cost of these new vegetation management programs?

A. Mindful of the significant damage to the Company's distribution property and wide-spread customer power outages in the St. Louis area resulting from the July 2006 wind storm and December 2006 winter storm, the State concurs that AmerenUE's new vegetation management programs, once fully implemented, should help reduce tree caused damage and outages related to future storms. However, there are implementation and cost monitoring concerns that should be addressed and considered by the Commission. These concerns arise, in part, due to the apparent absence of written planning documentation[11] and cost support for the identified new programs.

[10] Zdellar Supplemental Direct Testimony, p. 4.
[11] See AmerenUE responses to AG/UTI-49, AG/UTI-50, AG/UTI-51, AG/UTI-52, AG/UTI-54 and AG/UTI-55, attached as State Schedule SCC-3.

Mr. Zdellar's supplemental testimony[12] discusses the four new vegetation programs in a manner that can only be described as very general, with little more information than is set forth in the earlier summary outline. As indicated by the response to Data Request AG/UTI-48, AmerenUE has been unable to provide any breakdown of the $15 million cost of the new programs, instead noting that the process to document and track such costs is under discussion with Staff. [13] Further, since the Company relies on outside contract services to perform its tree trimming and vegetation management, the general availability of additional contract resources may contribute to a "ramping" effect on program expenditures as new crews are staffed, trained and deployed.

Q. Does the State have any recommendations for Commission consideration as to how the interests of both the Company and its customers can be adequately protected during the start-up and implementation phase?

A. Yes, providing the Commission finds that AmerenUE is spending the money currently allotted and the Commission finds it necessary to approve the new vegetation programs. While other parties to this proceeding may offer additional recommendations, the Commission is encouraged to consider the following implementation conditions as it deliberates the Company's request. First, because the new programs include the removal and replacement of trees located outside of the Company's rights-of-way and private property easements, AmerenUE should form one or more local focus groups to obtain community input and feedback regarding its proposed efforts. The focus groups could include representatives from non-occupying landowners, business customers, residential

[12] Zdellar Supplemental Direct Testimony, p. 4.
[13] AmerenUE response to AG/UTI-48, attached as State Schedule SCC-4.

customers, and municipalities or other affected governmental entities. While the State has not exhaustively researched AmerenUE's rights and liabilities associated with any unilateral steps that might be taken to implement said programs, input from local focus groups could prove valuable in designing specific programs, obtaining property owner approval or commitment, developing action plans when property owners object to the planned removal or replacement efforts, enhancing customer communication, helping to minimize customer confusion, and identifying implementation obstacles.

Second, prior to spending or committing significant funds on the expanded programs, AmerenUE should be required to provide a formal planning document to the Commission and all other parties to this proceeding, within thirty (30) to sixty (60) days following the Commission's issuance of a final order. This planning document should provide detailed descriptions, objectives and milestones for each proposed program, along with a breakdown of the overall budget by program. In the absence of such information, it will be extremely difficult to assess the success or monitor the cost of the new programs.

Third, on at least an annual basis, AmerenUE should be required to submit a report to the Commission and parties of record discussing the planned and actual progress under each <u>new</u> program and explaining the need for any shifts in program focus that might arise from time to time. In addition, the report should also contain project cost information, including: the monthly and cumulative funds collected from ratepayers; the actual and budgeted monthly and cumulative expenditures on each program; and the amount of additional interest added to unspent available funds due to timing differences between program collections and expenditures.

Q. You previously indicated that the Company had been unable to provide any breakdown of the $15 million cost between the new programs. Does the State propose any cost guidelines that should be implemented with respect to these new programs?

A. Yes, provided that the Commission finds AmerenUE is spending the money currently allotted and finds it necessary to approve the new vegetation programs. The Company has indicated that the majority of the new expenditures will initially be committed to "removals on/off right-of-way and additional clearance."[14] At page 5 of his Supplemental Direct Testimony, Mr. Zdellar has also committed to separately track the amounts collected for the new programs and apply interest to the balance. However, no information has yet been presented as to the types of expenditures that would or would not qualify under the new programs. The State offers the following additional conditions to clarify how the additional funds are to be spent:

- Qualifying expenditures must be restricted to incremental clearing, removal, replacement or trimming work that would not have been undertaken under the trimming program implemented in January 2005.
- Separate work crews or vendors should be considered to perform traditional trimming vs. new program work. However, should the Company determine that efficiency and effectiveness is maximized by having the same work crews simultaneously undertake both traditional trimming and new program work,

[14] AmerenUE response to AG/UTI-48, attached as State Schedule SCC-4.

specific guidelines and procedures must be established in advance to ensure that the work crews are properly trained to assign and apportion work hours, equipment costs and common consumables between the traditional and new programs.

- No internal Company labor or overhead costs should be attributed or assigned to the new programs, unless AmerenUE hires new employees for in-house work crews or supervisory personnel dedicated to the new vegetation programs.
- None of the additional funds collected by the Company should be used or redirected to support capital projects.
- None of the additional funds collected by the Company should be used or redirected to reestablish service following a power outage or for trimming work associated with damage caused by future storms.

Q. At page 5 of his supplemental testimony, Mr. Zdellar indicates that the Company would separately track the new program funds and apply interest to the balance. How is the interest provision designed to function?

A. It is somewhat unclear, at the present time, exactly how this interest component will be applied. In response to Data Request AG/UTI-53, AmerenUE indicated that interest will be calculated on any unused balance at the end of the year, based on the Company's short term borrowing rate.[15] Although this State data request sought a multi-year, illustrative example of how the Company would track and apply interest to the account balance, the response only provided a general framework as to how the assumed collections from ratepayers would be allocated between months but failed to provide any illustration as to

[15] See AmerenUE response to AG/UTI-53, attached as State Schedule SCC-5.

how the amount of interest would be calculated. Because of the possibility that AmerenUE could elect to spend funds in advance of the assumed monthly collection from ratepayers, it is important that the interest provision not be applied in a manner that would penalize ratepayers (i.e., effectively charge ratepayers interest) for any such timing difference between collection and expenditure.

UNCOLLECTIBLE EXPENSE

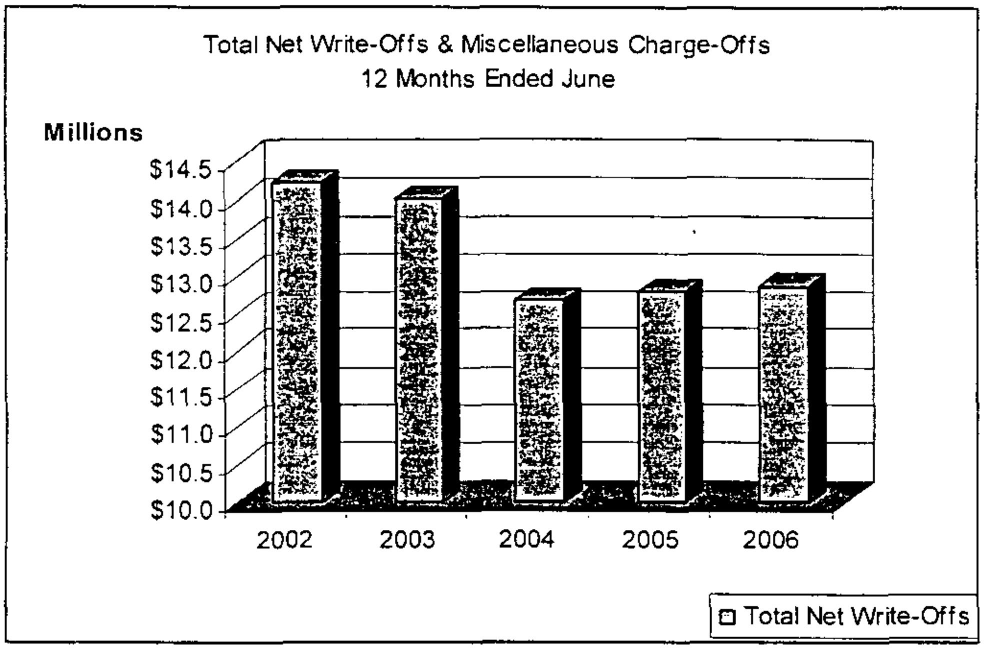
Q. Please describe State Adjustment C-13.

A. State Adjustment C-13 adjusts the level of uncollectibles included in test year expense to reflect a level of net write-off experience that has been fairly constant during the last several years. In light of the historical trends in both net write-offs and retail revenues, the State is recommending that the calculation of overall revenue requirement not include a separate component to recognize additional uncollectibles, or bad debts, on any rate change resulting from this proceeding.[16] Instead, the State's proposed level of uncollectible expense incorporates a reasonable, ongoing level of such costs in the determination of overall revenue requirement.

Q. How does the level of uncollectible expense included in the Company's test year expense compare with actual net write-offs incurred by AmerenUE during recent years?

[16] The calculation of the revenue conversion revenue factor, with and without an uncollectible factor, is set forth on State Schedule A-1.

A. The Company pro forma results of operations include about $13.7 million of uncollectible accrual basis expense.[17] As shown by the following chart, AmerenUE has experienced lower levels of actual net write-offs in recent historical years:[18]



During the fiscal years ending June 2004 through June 2006, total net write offs ranged from $12.67 million to $12.86 million – or about $1 million less than the $13.7 million of uncollectible expense included in the Company's pro forma test year expense.

Q. Does the Company record uncollectible expense based on actual net write-off activity?

A. No. In typical accounting for uncollectible activity, a company will estimate the reserve level that should be set aside for bad debts and record monthly accrual journal entries debiting expense (Account 904) and crediting the uncollectible reserve (Account 144). When a customer's bill is deemed to be uncollectible, the accounts receivable would be

[17] AmerenUE response to Data Request AG/UTI-268.
[18] AmerenUE response to Staff Data Request MPSC-294.

written off by crediting the customer's account (Account 142) and debiting the uncollectible reserve (Account 144). Any subsequent collection of prior write-offs are credited to the uncollectible reserve to restore the amount previously written off. As a result, the monthly accrual of bad debt expense is not based on actual uncollectible activity.

However, in setting utility rates, the uncollectible reserve account can and should be analyzed to evaluate historical levels of net write-off and subsequent collection experience for comparison with the level of uncollectible expense included in pro forma operating results.

Q. The above chart shows a fairly significant decline in net write-offs during the five year period presented. How has the level of retail revenues changed over time?

A. While I do not have retail revenue information for the same time period, the following proprietary graph presents retail revenues on a rolling twelve month basis, which helps to illustrate general trends in the underlying revenue data.

** **

Q. How did the Company determine, or quantify, the $13.7 million of uncollectible expense included in pro forma operating results?

A. The $13.7 million represents actual level of uncollectible accruals recorded by AmerenUE during the test year. However, the Company's filed revenue deficiency of approximately $374.7 million includes an allowance for an additional $2.1 million[19] of uncollectible expense on the rate increase asserted by AmerenUE. In the aggregate, the Company's overall revenue requirement includes about $15.8 million for bad debts.[20]

Q. You previously indicated that the State was not recommending that uncollectibles be included in the determination of the revenue conversion factor. Can you please explain the basis for that recommendation?

[19] AmerenUE Schedule GSW-E37.

[20] $13.7 million test year uncollectible accruals plus $2.1 million of uncollectibles on the asserted revenue deficiency equals $15.8 million requested for recovery in rates.

A. Yes. In its supplemental filing, AmerenUE effectively increased the pro forma revenue requirement by an additional 0.56% factor, above and beyond the test year actual levels, to allow for additional uncollectible expense recoveries. Because of the favorable decline in net write-offs since 2002 and the almost imperceptible change in net write-offs during the past three years when retail revenues increased substantially, the State's pro forma level of uncollectible expense should provide the Company with adequate cost recovery, without a separate bad debt factor-up. For this reason, uncollectibles are properly excluded from the computation of the test year revenue conversion factor as set forth on State Schedule A-1.

EXPIRING AMORTIZATION ADJUSTMENT

Q. Please describe State Adjustment C-14.

A. State Adjustment C-14 is designed for to achieve two objectives. First, this adjustment eliminates the amortization included in test year expense associated with the costs the Company incurred during the Missouri electric complaint case (Case No. EC-2002-01). According to the response to Data Request AG/UTI-147, this amortization terminated in June 2006.

Second, the Company has proposed to include a full year of amortization expense for both Missouri merger costs and Year 2000 ("Y2K") implementation costs, even though these amortization are scheduled to expire in December 2007 and March 2008, respectively. Since the rates resulting from the instant proceeding are reasonably expected to be in effect for more one year and well beyond the termination of the merger and Y2K cost amortizations, this adjustment reschedules over a four-year period the unamortized balances as of the effective date of the rates from this proceeding.

Complaint Case Amortization

Q. Please describe the Missouri complaint case amortization.

A. According to UE's responses to Data Requests AG/UTI-145 and AG/UTI-147, the Company incurred and deferred as a regulatory asset approximately $4.3 million of expenditures related to an earnings complaint case filed by Staff in July 2001. The Company's response to Data Request AG/UTI-147 indicates that the stipulation in Case No. EC-2002-01 authorized the amortization of these costs over a 51-month period, with the charge to FERC Account 928, Regulatory Commission Expense. This amortization started in April 2002 and terminated in June 2006.

Q. Did the Company recognize an adjustment to remove this amortization from test year expense?

A. No.[21]

Q. In quantifying the Company's proposed amortization of the costs to process the pending rate case, did UE compare the pro forma rate case expense amortization with the complaint case amortization embedded in test year expense to quantify a net adjustment for rate case expense?

[21] AmerenUE response to AG/UTI-145(b).

A. No. The Company workpaper[22] supporting UE O&M Adjustment #17 includes the full amount of the proposed rate case expense amortization in test year expense. In other words, the Company did not net these two amortizations.

Q. Why should the expired complaint case amortization be removed from test year expense?

A. At the time of the complaint case, the Company was allowed to defer and amortize certain costs of processing the complaint. The amortization has now expired, in the last month of the historic test year. If the now expired amortization is not eliminated from test year expense, the Company will effectively be allowed to continue to recover the amortization during the entire term that the rates resulting from this case are in effect. Rather that allow the Company to structurally over-collect its complaint case costs, State Adjustment C-14 properly removes these costs from test year expense.

Merger & Y2K Cost Amortization Rescheduling

Q. Please describe the Merger cost amortization recorded by the Company.

A. According to UE's responses to Data Requests AG/UTI-108 and AG/UTI-145, the Company incurred and deferred as a regulatory asset approximately $34.4 million of merger costs resulting from the merger of the Union Electric Company and Central Illinois Power Company, which created Ameren Corporation. In response to Data Request AG/UTI-108, the Company indicated that the Commission authorized the amortization of the regulatory asset over a 10-year period, beginning January 1998 and ending December 2007, in Case No. EM-96-149. The Company has included a full year amortization of $3.3 million (electric) in test year expense.

[22] AmerenUE workpaper GSW-WP-E1324.

Q. Please describe the Y2K cost amortization recorded by the Company.

A. Leading up to January 1, 2000, significant concerns across the nation focused on the readiness of embedded software programs to successfully recognize dates subsequent to calendar year 1999. In order to ensure the integrity of computer systems and processes, companies typically assigned significant resources to review, re-write and modify installed software to accommodate the transition into the Year 2000. In response to Data Request AG/UTI-108, AmerenUE disclosed that its Y2K costs were amortized over a 6-year period, beginning April 2002 and ending March 2008 (Case No. EC-2002-01). A full year amortization of about $836 thousand was included in test year expense

Q. Why is this State adjustment necessary?

A. As a result of a ten-year and six-year amortization periods and an effective date of January 1, 1998, these one-time costs will be fully amortized as of December 31, 2007, and March 31, 2008, respectively. Due to the timing of the Company's decision to file its rate increase request in early July 2006, the effective date of the Commission's rate order can be expected no later than early June 2007. Absent some form of rate case adjustment to recognize the known, certain and measurable effect of the expiration of both amortizations, the Company would be guaranteed to commence over-recovering these one-time within seven to ten months following the issuance of a Commission order in the pending proceeding. Such an over-recovery of those merger and Y2K costs would clearly be an unintended result of past regulatory actions to allow recovery of such one-time costs through ten year and six year amortization periods.

Q. You indicated that a four-year time period was proposed for purposes of implementing the State's rescheduling amortization. What was the basis for selecting the four-year period for rescheduling purposes?

A. As discussed in the rate case expense section of my testimony, the Company has proposed tariffs in this case to implement a fuel adjustment clause ("FAC"). Because the Commission's FAC rules 4 CSR 240-20.090 require that the utility file a new rate case at least by the end of the fourth year, a four-year amortization period was selected for application in the State's rescheduling adjustment and rate case expense adjustment.

Q. Could you explain the nature and intent of this type of amortization "rescheduling" adjustment?

A. Yes. Typically, non-capital costs (i.e., period costs) incurred by a regulated entity are chargeable directly to expense in the year incurred, unless cost deferral authorization is approved by a regulatory body having rate jurisdiction over the company's operations. Regulators occasionally allow regulated companies to defer and amortize a variety of one-time costs including such items as extraordinary storm damage costs, demand-side management costs, unusual maintenance costs, accounting transition costs, merger costs, etc. However, the authorization of such deferrals normally occurs in conjunction with determinations as to the aggregate amount to be amortized, the effective date of the commencement of the amortization and the specific time period over which such costs will be amortized.

Although such amortizations may commence with the effective date of a regulatory decision implementing a change in utility rates, the expiration of such regulatory amortizations rarely conform to the exact timing of a rate order in a subsequent rate case. Consequently, ratemaking adjustments may be required to ensure that the specific costs authorized for deferral and amortization are not materially over-recovered or under-recovered from ratepayers. Amortization "rescheduling" adjustments focus on this timing differential and eliminate, or at least minimize, inappropriate cost recovery attributable to the relative infrequency of rate filings and the resulting regulatory lag.

Q. In the absence of State Adjustment C-14, what would be the amount of the over-recovery during the first rate year?

A. For example, assuming the Commission included the entire $3.4 million of annual merger cost amortization in test year expense and UE would cease recording the amortization seven (7) months later, the Company would over-collect about $1.42 million during the first rate year following the issuance of said order, as shown by the following table:

	Amount
Annual Amortization Include in Rates	$3.40 million
Less: Remaining Amortization ($3.4 million * 7/12ths)	(1.98) million
Structural Over-Collection in First Rate Year	$1.42 million

Absent the amortization rescheduling adjustment proposed by the State, the Company would theoretically continue to over-recover approximately $3.4 million of merger costs per year for each additional rate year until a rate order is issued in the next following rate case. Although the amount at risk is smaller for the Y2K amortization, the same theory applies.

Q. Does State Adjustment C-14 simply reduce test year expense by the amount of the annual merger cost amortization embedded therein?

A. No. Because there will be an unamortized balance of deferred merger costs at the effective date of the pending rate case, the amortization of the unamortized balance would be rescheduled over the period the new rates are expected to be in effect – in this case, four years. The concept underlying amortization "rescheduling" adjustments considers four basic questions:

1. What is the amount of the unamortized deferral as of the end of the test year?

2. What is the amount of the unamortized deferral as of the expected date of the rate order in the pending rate case?

3. When is the terminal, or completion, date of the currently authorized amortization?

4. What is the expected duration, or life, of the new rates to be authorized by the Commission in the pending rate case?

With this information, it is possible to determine whether any unamortized balance is material to the Company's overall operations. If so, the remaining period of the original amortization can be compared to the expected life of any new rates to assess whether it is necessary to "reschedule", or modify, the period over which any material remaining balance should be amortized for ratemaking purposes.

When the remaining period of the current amortization is substantially equal to the expected duration of new rates, a separate "rescheduling" adjustment would not be necessary, because the company should recover substantially sufficient revenues related to the amortization expense over the entire period the new rates are expected to remain in effect. However, if the remaining period of amortization is significantly shorter than the expected "life" of the new rates, the failure to adjust the amortization for ratemaking purposes would result in the continuation of the related revenue stream (i.e., from ratepayers to the utility) well beyond the expiration of the book amortization expense. This situation would cause a structural over-collection of the deferred amount originally amortized. In my opinion, this over-collection would improperly default into operating income to the benefit of the Company and its shareholders until rates are subsequently revisited.

Q. Earlier, you indicated that you did not believe that the Commission intended for the Company to over-recover these deferred amounts. What is the basis for your opinion?

A. When regulators authorize the deferral and amortization of one-time costs for ratemaking purposes, it has been my experience that the expectation is that the specified costs will be recovered from ratepayers – no more, no less. At the time the amortization is established, the understanding is that the amortization and recovery of the amount deferred will commence and terminate at specified points in time. Unfortunately, if rates are not automatically reduced when the amortization expires or the amortization is not "rescheduled" to better synchronize the period of amortization with expected rate changes, a structural over-collection will be introduced into the ratemaking process.

Absent detailed accounting or other mechanisms to address the disjoint between the amortization expiration and rate change dates, ratepayers would over-compensate the company for the specified costs levels originally intended for recovery.

Q. Do you believe that the December 2007 and March 2008 expirations of the merger and Y2K amortizations represent known and measurable changes that should be recognized in the current proceeding so that cost of service is representative of ongoing cost levels?

A. Yes. When the regulatory process allowed these deferrals and amortizations, the "dates" that the amortizations would start and stop were known with certainty, just as they are today. During the 2002 complaint case, it was not necessary to explicitly address or consider the ratemaking implications of the expiration of these amortizations, because there were ongoing. However, the current rate case is unique as it applies to both amortizations, because they will expire seven to ten months after the effective date of the Commission's rate order in this docket.

Q. When is the Commission expected to issue its order in this proceeding?

A. According to Section 393.150 RSMo, the Commission must issue a rate order within eleven months after the utility files its rate increase request, or the rate request is final as proposed. Since the Company filed the testimony and exhibits supporting its requested rate increase on July 5, 2006, the suspension period should lapse in early June 2007.

Q. Do you believe that the expiration of this amortization is an out-of-period transaction or violates the January 1, 2007, true-up provision specified in the Commission's Procedural Order?

A. No. Certainly, the terminal date of the amortizations do occur subsequent to January 1, 2007. However, the "transactions" which gave rise to these amortizations occurred a number of years ago. The issue for the Commission to address is whether the Company should be allowed to over-recover the deferred costs through future rates at ratepayer expense. In my opinion, such action would be unnecessary and inappropriate, particularly given the Company's proposed elimination of the negative depreciation expense that it has been recording on its books and records since the 2002 complaint case.

Q. Could you explain your reference to the negative depreciation expense the Company has been recording since the complaint case?

A. Yes. Section 8 of the Stipulation and Agreement in Case No. EC-2002-1 required UE to modify its dismantling costs and/or service lives for certain assets resulting in a reduction to book depreciation expense of approximately $20 million annually from then current depreciation expense levels. If a collaborative effort between Staff and UE did not result in revised depreciation rates designed to decrease annual depreciation expense by $20 million, the Company was authorized to book a negative annual amortization of $20 million effective April 1, 2002.

Q. Why do you believe that this situation is relevant to the reasonableness of the State's proposed rescheduling of the merger cost amortization?

A. Section 8 of the Stipulation and Agreement does not specify a sunset date for the negative depreciation expense to terminate. According to the Company's response to Data Request AG/UTI-221, AmerenUE records about $1.67 million of negative depreciation expense each month (i.e., $20 million divided by 12 months), which also serves to decrease the accumulated depreciation reserve balance (increasing rate base) by a like amount.

In the absence of an earlier sunset provision, the Company will continue booking negative depreciation expense until new depreciation rates are approved and implemented. Since the Company has proposed new depreciation rates in this docket, it is anticipated that UE will cease recording $1.67 million of negative depreciation expense each month on the effective date of the Commission's rate order in this proceeding.

Notably, the effective date of the Commission's rate order is anticipated to occur in early June 2007, about five months after the January 1, 2007, true-up cutoff date. However, Company Depreciation Adjustment #5 has the effect of increasing book depreciation to eliminate the $20 million of negative depreciation expense. It would see inconsistent, from a ratemaking perspective, for the true-up cut-off to be interpreted in such a way that the Company is allowed to remove a $20 million negative expense from the test year but require the continued recognition of a positive a $3.4 million and a positive $836 thousand annual amortizations that expire seven to ten months later – particularly, when all three items terminate after the true-up cutoff date. Further, if the merger and Y2K amortizations are not rescheduled as proposed by the State, then why should the negative $20 million depreciation expense be excluded from cost of service?

After all, the State's rescheduling recommendation is not seeking to deny any recovery of the unamortized balance of deferred merger or Y2K costs. Rather, the rescheduling would merely lengthen the period over which the deferred costs would be recovered, thereby balancing the interests of both ratepayers and the Company.

PRO FORMA DEPRECIATION ANNUALIZATION

Q. Please describe State Adjustment C-15.

A. State Adjustment C-15 represents the annualization of depreciation expense based on the depreciable plant included in rate base and the existing depreciation rates currently authorized by Commission.

Q. How was the amount of this State adjustment quantified?

A. Book depreciation was annualized by multiplying the various authorized depreciation rates, by FERC account, by the related depreciable plant investment estimated at December 31, 2006. The aggregate amount of the annualized depreciation was then compared to the annualized level included in the Company's pro forma operating expense in order to calculate the value of this State adjustment.

Q. Has UE proposed any ratemaking adjustments to the recorded level of book depreciation expense?

A. Yes. Referring to UE Schedule GSW-E30-2, the Company's supplemental filing recognizes five (5) separate adjustments to book depreciation and amortization expense, as summarized below:

UE Adj.#	Description	Company Depreciation Adjustments
1	General Facility Allocation to Gas	$ (132,000)
2	Plant Additions July-Dec 2006 @ UE Proposed Rates	8,468,000
3	Plant Balance at June 30, 2006 @ UE Proposed Rates	41,311,000
4	Venice Plant 10-Year Amortization of Removal Costs	174,000
5	Eliminate Depr. Stipulation in Case No. EC-2002-1	20,000,000
	Total Pro Forma Depreciation & Amortization Adj.	$ 79,821,000

Source: UE Schedule GSW-E30-2.

Because of the presentation format employed in developing the State Joint Accounting Schedules, State Adjustment C-15 sets forth the various elements comprising the calculation of the State's proposed adjustment. As indicated previously, State Adjustment C-15 represents the incremental adjustment to the Company's pro forma depreciation expense to recognize the update of depreciable plant through December 2006 and the existing book depreciation rates previously approved by the Commission.

Q. In the earlier discussion of State Adjustment B-1 to update plant in service, accumulated depreciation reserve and the accumulated deferred income tax reserve through year-end 2006, you discussed the State's rate base inclusion of certain plant additions for new business, during the period July through December 2006, that the Company did not include in rate base. Does State Adjustment C-15 provide an annual level of depreciation on new business plant additions that occurred subsequent to the test year?

A. Yes.

Q. Why is State Adjustment C-15 based on the existing book depreciation rates previously approved by the Commission?

A. For purposes of this proceeding, the State did not retain consulting services to evaluate and critique the new depreciation rates proposed the Company. Although State witness Brosch does provide testimony addressing the Company's presumption that the Callaway Nuclear Plant will be retired at the end of its initial operating license and that the assumed retirement of the entire fleet of coal fired steam units within twenty years as not credible, the State does not sponsor nor propose any change in book depreciation rates. Consequently, State Adjustment C-15 is based on the current book depreciation rates.

Q. Is the recommendation of the State that the Commission should freeze UE's book depreciation rates at existing levels?

A. No. Other than Mr. Brosch's life extension and retirement testimony, the State has not taken a position regarding the Company's requested changes in book depreciation rates.

Q. If State Adjustment C-15 does not reflect any change in book deprecation rates and the State is not offering an alternative proposal, would you agree that the overall revenue requirement quantified by the State would be significantly understated assuming the Commission were to approve revised depreciation rates?

A. No, not necessarily. Although the State has not quantified a separate expense adjustment for a change in book depreciation rates, the Commission Staff and other intervenors in this proceeding may present proposed book depreciation rates that are close to or materially different from those recommended by the Company. The currently authorized depreciation rates are the only known and certain rates at the present time.

RATE CASE EXPENSE

Q. Please describe State Adjustment C-16.

A. This adjustment represents the State's recommendation that rate case expense be updated to actual amounts later in this proceeding and amortized over a four-year period.

Q. Why should rate case expense be updated to actual levels?

A. In its supplemental filing, the Company estimated the cost of processing the electric rate case at about $4.6 million, including costs for outside counsel, legal fees and travel expenses. In response to Data Request AG/UTI-222 (which referred to the highly confidential response to Staff Data Request 30), the Company provided actual rate case expense as of July 2006. Rather than set rates based on estimated costs or rely on early project cost amounts, it is more appropriate to recognize actual rate case costs, presuming that such amounts are not excessive.

Q. Did the Company propose to amortize rate case expense for ratemaking purposes?

A. Yes. At page 21 of his supplemental direct testimony, Company witness Weiss proposes to amortize $4.6 million of electric rate case expense over a three-year period, resulting in an annual amortization of about $1.5 million.

Q. If the Company has proposed to amortize test year rate case expense, why is State Adjustment C-16 necessary?

A. This adjustment is necessary for two reasons. First, this adjustment serves as a placeholder to replace the Company's estimated costs with actual costs later in this proceeding.

Second, given the magnitude of the Company's rate case estimate (i.e., $4.6 million), UE's three-year amortization period creates an increased over-collection risk to customers, if the time lag to process the Company's next rate case exceeds three years. The objective for recognizing the amortization of rate case expense in cost of service is to provide a ratable mechanism for recovery of the costs reasonably incurred by the utility to pursue an increase in rates. That objective is neither to deny recovery of reasonably incurred cost levels nor provide for a structural over-recovery of those costs. By extending the amortization period, as proposed by the State, a significant amount of rate case expense is recovered through rates on an annual basis, while reducing the potential over-recovery if the next rate case proceeds on a longer time interval.

Q. What is the basis for UE's proposed three-year amortization of rate case expense?

A. In quantifying the amount of rate case expense to include in the test year, the Company's response to Data Request AG/UTI-223 cited to the Electric Utility Fuel and Purchased Power Cost Recovery Mechanism rules as support for the three-year amortization period, stating:

> "The Electric Utility Fuel and Purchased Power Cost Recovery Mechanism rules require that a new rate case be filed with new rates in effect at least by the end of the 4th year. Thus a new rate case would need to be filed approximately 3 years after new rates are approved."

While I certainly understanding the logic of the Company's linkage of the filing cycle to the new fuel clause rules, I believe that the arithmetic is inaccurate. If one had access to a crystal ball that could foresee the timing of the Company's "next" rate case, it would be possible to measure to the day the time lapse between the effective date of the current rate proceeding and the effective date of the next rate proceeding. Even though Missouri statutes provide for a maximum eleven month suspension period, the <u>filing</u> of a utility's rate case is not indicative of the interval between the effective dates of the final orders in two rate cases. Assuming that the Commission's new fuel clause rules trigger the "next" rate case so that rates are "in effect at least by the end of the 4th year," it would seem that a four-year, rather than a three-year, amortization period would be more appropriate to minimize any structural over-collection of rate case expense. On the other hand, if it were known with certainty that AmerenUE would file its "next" rate case with a three-year interval between the effective dates of the rate cases, I would be supporting of a three-year amortization period.

Q. What are the Company's plans for a "next" rate case?

A. As indicated in response to Data Request AG/UTI-223, the Company has not prepared or developed any formal planning assumptions for its next rate case. If one were to consider history as a potential indicator of future rate activity, the most recent Company initiated rate filing before the current rate case, excluding the complaint case filed by Staff in 2001, was in the mid-1980's when the Callaway nuclear facility was brought on line and included in rate base. Although the Company operated under an experimental regulatory plan for several years prior to the Staff initiated earnings complaint case, such plans do not represent traditional rate case activity. Since history is not a viable source to develop an average interval between UE initiated rate cases, the State encourages the adoption of a four-year amortization period as a reasonable interval between rate cases.

INCENTIVE COMPENSATION

Q. What is the purpose of State Adjustment C-17?

A. In quantifying overall revenue requirement, Company O&M Adjustment #2 decreases the amount of incentive compensation accrued during the test year "...by $3,200,000 to reflect the amount of incentive compensation annualized at the target level for calendar year 2006."[23] State Adjustment C-17 represents a partial disallowance of the Company's annualized incentive compensation expense. This adjustment recognizes overall incentive costs at the threshold rather than target level and removes plan costs associated with financial metrics, while allowing ratemaking recovery of other metrics reasonably benefiting ratepayers such as individual, customer satisfaction, safety and service quality performance measures. After the State's proposed adjustment, the test period will

[23] Weiss Supplemental Direct Testimony, p. 18.

include approximately $4.3 million of incentive compensation expense, before jurisdictional allocation.

Q. Please describe the incentive programs offered by the Company.

A. Although AmerenUE offers several plans designed to incent and/or reward certain actions and behaviors by its work force,[24] the Company maintains several ongoing incentive plans, which are summarized below:[25]

- **<u>Ameren Incentive Plan (AIP)</u>:** ** [redacted] **

- **<u>Ameren Management Incentive Plan (AMIP)</u>:** ** [redacted] **

- **<u>Executive Incentive Plan (EIP)</u>:** ** [redacted] **

In general terms, each incentive plan contains unique performance components or metrics. However, there is a common "financial" metric throughout the three plans. For example, the Summary section of the current AMIP plan document states that the plan is ** [redacted]

[24] For example, AmerenUE and Ameren Corporation employees may qualify for certain bonuses based on exceptional performance or generation outage plans. Those bonus plans are intentionally excluded from this discussion of the Company's incentive compensation plans.

[25] AmerenUE highly confidential response to Staff Data Request MPSC-50.

[redacted] ** While the AIP and EIP documents contain variations on the AMIP payout metric language, the Company's response to Data Request AG/UTI-86 provides the following discussion of how the level of funding for each these plans is determined:

> Ameren's annual incentive plans are all funded based on corporate Earnings Per Share (EPS). The Board of Director's determines the EPS performance level that will be used to fund the incentive programs. This EPS value may differ from published EPS results due to discretionary adjustments made by the Board in recognition of significant events outside employee control that affected corporate performance. The plan percentage payouts are interpolated based on where the EPS performance falls relative to the threshold, target or maximum rates.

For the 2005 plan year the following table summarizes the EPS performance parameters:[26]

PLAN YEAR: 2005

PERFORMANCE LEVEL	ORIGINAL EPS PERFORMANCE	ADJUSTED EPS PERFORMANCE	ADJUSTMENT DETAIL
Threshold	$2.80	NA	No adjustment was made by the Board
Target	$2.95	NA	
Maximum	$3.15	NA	

2005 EPS FUNDING ADJUSTMENTS

2005 EPS PERFORMANCE	ADJUSTMENT DETAIL
$3.02	Reported 2005 EPS
$0.11	Excluded charge to earnings added back
$3.13	2005 Funding EPS

EXPLANATION: In February 2006, Ameren reported 2005 earnings of $3.02. This included an 11 cent charge to earnings for the required adoption of an accounting standard related to asset retirement obligations. At the February 10th meeting, Ameren's Board of Directors agreed to exclude the 11 cent charge and fund the 2005 annual

[26] AmerenUE response to Data Request AG/UTI-86.

incentive plans at \$3.13 per share. The exclusion of one-time gains or losses associated with the adoption of new accounting principles for incentive compensation purposes is consistent with past practice.

Q. You earlier indicated that the Company's pro forma incentive compensation was annualized at the target level for calendar year 2006. How does the target EPS level considered in the Company's 2006 annualization adjustment compare to the actual and target EPS results for 2005 and prior plan years?

A. The consolidated 2006 earnings per share Target EPS, listed below, is higher than all plan year Target EPS during the period 2000-2005, except for 2001:[27]

Threshold	\$2.96
Target	\$3.15
Maximum	\$3.35

The following table provides a concise chronology of EPS targets and actuals for this entire period by plan year:[28]

	Earnings Per Share (EPS)			EPS	EPS
PLAN YEAR	**Threshold**	**Target**	**Maximum**	**Funding**	**Achieved**
2000	\$3.05	\$3.15	\$3.25	\$3.33	\$3.33
2001	\$3.20	\$3.45	\$3.65	\$3.28	\$3.41
2002	\$2.92	\$3.12	\$3.32	\$3.04	\$2.61
2003	\$2.66	\$2.76	\$2.96	\$2.95	\$3.25
2004	\$2.57	\$2.72	\$2.92	\$2.84	\$2.84
2005	\$2.80	\$2.95	\$3.15	\$3.13	\$3.02

Clearly, there are material fluctuations in both target and actual EPS results over this six-year time frame.

[27] AmerenUE response to Data Request AG/UTI-88.
[28] AmerenUE response to Data Request AG/UTI-140.

Q. You also stated that one component of State Adjustment C-17 was to recognize overall incentive costs at the threshold rather than target level. Could you explain that reference?

A. Yes. For the 2006 plan year, the Target EPS is $3.15 and the Threshold is $2.96. As EPS increases, the amount of incentive compensation that may be paid out to employees also increases. So, the amount of annualized incentive pay at the Target EPS will be higher than at the Threshold EPS.

Q. How did you quantify the amount of incentive compensation at the Threshold EPS?

A. In the highly confidential response to Data Request AG/UTI-1, the Company provided a copy of the workpapers supporting its various adjustments to rate base and operating income. One of the workpapers contained therein[29] provides annualized 2006 incentive compensation amounts for AIP, AMIP and EIP using forecast EPS at the Threshold, Target and Maximum levels. This data source was used in the quantification of State Adjustment C-17.

Q. Once the annualized level of incentive compensation was reduced from the Target to the Threshold EPS level, how did you assess whether the revised amount should be recognized in quantifying overall revenue requirement?

A. After determining the annualized Threshold level of incentive compensation, the objectives of the various performance award components, or metrics, were then reviewed to identify acceptable parameters to support cost recovery.[30]

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29 UE Workpaper GSW-E1152.

30 Financial components or metrics were eliminated, while customer focused or direct employee performance components were allowed.

Q. Please briefly describe the various components or metrics of the AMIP and EIP incentive programs.

A. While some Business Lines have slightly different components, the 2006 AMIP is generally based on two components: **[redacted].** The 2006 EIP has three components: **[redacted].** The following table summarizes plan parameters for the AMIP and EIP incentive programs:

	Weighting Weight	% Payout
AMIP:		
**[redacted]	[redacted]	**
**[redacted]	[redacted]	**
Total	100%	
EIP:		
[redacted]	[redacted]	**
[redacted]	[redacted]	**
[redacted]	[redacted]	**
Total	100%	

Source: Company highly confidential response to Staff Data Request MPSC-50.

Specimen examples of the employee performance assessment process have been reviewed and found acceptable for purposes of determining ratemaking recovery. However, **[redacted]** are often found to be heavily weighted to financial targets, with modest component elements tied to customer focus or employee performance targets. As indicated previously, corporate EPS targets (i.e., Threshold EPS) must be met before any annual incentive payment may be made to otherwise eligible employees.[31]

[31] AmerenUE response to Data Request AG/UTI-86.

Q. Did you review any KPI documentation to support the quantification of State Adjustment C-17?

A. Data Requests AG/UTI-141 and AG/UTI-142, submitted to the Company on November 6, 2006, sought descriptive listings of the KPI for each Business Line used in administering the 2006 AMIP and EIP incentive programs. The requested documentation was received from the Company on December 13, 2006 – too late to allow adequate time for the review and evaluation of such data. As a placeholder, State Adjustment C-17 effectively disallows 50% of the KPI component, pending a review of KPI documentation supplied in response to Data Request AG/UTI-141.

Q. Why have you proposed to disallow a significant portion of the test year incentive plan cost?

A. There are several reasons why this adjustment is appropriate. First, the determination as to the overall pool of funds available under the incentive plans focus on Ameren's corporate-wide financial results, including regulated entities located in other States and non-regulated entities. Those Company employees directly or indirectly supporting the provision of regulated electric service in the State of Missouri have limited ability or opportunity to materially affect the consolidated financial results of Ameren. Efforts to enhance consolidated financial results may not be consistent with the interests of the Company's Missouri retail customers or reasonable pricing of regulated services.

Second, the consolidated financial targets are not directly linked to customer service, employee safety, cost reductions, individual employee performance or operational achievements or efficiencies in the Company's Missouri service territory.

Third, to the extent that the inclusion of financial targets in the incentive plans assists the Company in achieving improved financial results, the cost of the Company's discretionary incentive plan should be funded by the increased levels of net income, cash flow and other financial resources, rather than through inclusion in the determination of overall revenue requirement used to support prices charged to AmerenUE's retail customers.

Obviously, a decision by management to incur incentive compensation costs is an indication that such costs were viewed as reasonable by the Company, but regulators need not allow above-the-line accounting for all discretionary costs incurred by management absent a showing that such costs provide direct, tangible benefits to ratepayers. With this in mind, the State proposes recovery of the cost of those incentive plan metrics reasonably identifiable with customer service, employee safety, cost reduction, individual employee performance or operational achievements or efficiencies.

Q. Earlier, you stated that "regulators need not allow above-the-line accounting for all discretionary costs incurred by management absent a showing that such costs provide direct, tangible benefits to ratepayers." Could you further elaborate on this statement?

A. Yes. In general terms, the mere incurrence of a cost by a utility is not sufficient to ensure recoverability from ratepayers. Costs must be actually incurred, reasonable in amount, necessary for utility purposes and of direct benefit to ratepayers. While utility management has broad discretion as to how it spends its available resources, the ultimate question is the extent to which ratepayers should bear the burden of the utility's costs. In considering amendments to Part 65 of the Federal Communications Commission ("FCC") rules prescribing the components of rate base and net income for dominant carriers, the FCC discussed the framework surrounding its proposed changes.

> 7. In developing our proposal, we were guided by two historically applied principles – the "used and useful" standard and the benefit-burden test. The "used and useful" standard denotes property dedicated to the efficient conduct of a utility's business, presently or within a reasonable period. That standard reflects the principles that owners of public utilities must receive an opportunity to be compensated for the use of their property in providing a public service and that ratepayers must not be forced to pay a return on investment that does not benefit them directly. The benefit-burden test is based on the principle that the party who bears the financial burden of a particular utility activity should also reap the benefits resulting therefrom. We proposed to apply these two general principles to specific assets and asset categories established in Part 32 of our Rules, which will become effective January 1, 1988. [footnote omitted][32]

Although incentive compensation is only partially allocable between capital and expense accounts, the State's approach follows the conceptual framework of the "benefit-burden" test. In other words, the party who benefits from a particular transaction or activity should bear the related financial burden. If Missouri ratepayers have not benefited from the achievement of the incentive targets (i.e., improvement in consolidated financial results) or the Company employees supporting Missouri operations can not substantially contribute to or otherwise impact the achievement of those results, ratepayers should not

[32] CC Docket No. 86-497, FCC Report and Order, released December 24, 1987, par. 7.

be responsible for that portion of incentive plan costs related to consolidated financial results.

Incentive compensation is a method of providing monetary awards to the work force through unguaranteed payment programs, in addition to base wages. Incentive compensation plans are typically designed to attract, retain and motivate employees, enhance teamwork and high levels of achievement, and to facilitate the accomplishment of specific corporate, business unit and individual goals. By linking employee compensation to predetermined targets or objectives, individual employees are theoretically incented to perform well by directly influencing their day-to-day actions and activities – because if they do not achieve the established target levels, they will not receive incentive compensation pay.

Q. If Ameren fails to achieve the corporate financial targets or employees do not meet individual performance goals, will shareholders be required to forego all benefits associated with the inclusion of incentive plan costs in utility rates?

A. No. Since incentive compensation is "at-risk" to the employee, the amount of such compensation from year to year is not fixed, regular nor even certain to occur. In the event that minimum targets are not met, employees do not receive incentive payments and the amount of incentive compensation included in rates (e.g., AmerenUE has sought recovery of about ** [redacted]** of incentive pay, before jurisdictional allocation) would contribute to increasing utility profits. In other words, ratepayers would be placed at-risk to fund the level of incentive plan costs included in base rates, regardless of payout, while employees would be at-risk because targets might not be achieved for any number of reasons. At the same time, neither the Company nor its shareholders would necessarily be at-risk with respect to the amount of incentive pay included in test year expense, because the allowed expenses would be recovered through rates, regardless of future payouts.

Q. Since State Adjustment C-17 proposes to reduce test year incentive compensation expense, would this same theory apply to the remaining costs?

A. Yes.

MISO CORRECTION

Q. Please describe State Adjustment C-12.

A. In quantifying pro forma O&M expense, Company witness Weiss discusses two operating expense adjustments to reflect an increase in MISO transmission operation fees that became effective in 2006 (O&M Adjustment #10) and a reduction in MISO power market fees due to lower initial start-up costs than originally anticipated (O&M Adjustment #11).[33] State Adjustment C-12 is comprised of three components associated with the Company's two Midwest Independent Transmission System Operator, Inc. ("MISO") pro forma adjustments.

First, when AmerenUE assembled its per book expense for the test year ended June 30, 2006, the Company inadvertently excluded $3.4 million of actual charges associated with MISO Day 2 transmission expenses from the test year expense amounts. However, when the Company quantified O&M Adjustment #11, the $3.4 million was recognized as if the

[33] Weiss Supplemental Direct Testimony, pp. 20-21.

amount had been included in test year expense, effectively excluding the amount twice. State Adjustment C-12 recognizes the $3.4 million of test year transmission expense, thereby correcting for the double elimination.[34]

Second, AmerenUE O&M Adjustment #10 appears to inadvertently include charges for certain MISO Day 1 rate schedules[35] that were determined to have been terminated during the test year. State Adjustment C-12 removes these non-recurring costs from pro forma test year expense.[36]

Third, effective June 1, 2006, the method used to allocate MISO Schedule 10 costs between UE and CIPS was revised to reflect updated coincident peak load data. In quantifying pro forma test year expense, AmerenUE used a combination of actual and budgeted MISO Schedule 10 costs for calendar year 2006. Instead of applying the revised coincident peak allocation factor to all 2006 data, the Company only applied the new factors in the months of July through December 2006. State Adjustment C-12 applies the revised allocation factor to MISO Schedule 10 costs in all months of 2006.

Q. Does the Company agree with the first and second components of State Adjustment C-12?

A. Yes. I believe so. The Company confirmed in its response to Data Request AG/UTI-266 that the $3.4 million should be included in transmission expense. Further, the highly

[34] AmerenUE response to Data Request AG/UTI-266 & UE Workpaper GSW-WP-E1215.
[35] Direct Testimony of UE witness Maureen A. Borkowski, pp. 7-8, regarding MISO Rate Schedules 18, 19, 21 and 22.
[36] AmerenUE highly confidential response to Data Request AG/UTI-131 and revised UE Workpaper GSW-WP-E1190.

confidential response to Data Request AG/UTI-131 provides a revised UE workpaper showing the effect of eliminating the terminated MISO rate schedules from pro forma transmission expense.

Q. Does the Company agree with the third component of State Adjustment C-12?

A. I do not know. In response to the State's discovery in this proceeding,[37] it was determined that the Company's allocation of pro forma MISO Schedule 10 costs was based on two different factors to apportion cost responsibility between CIPS and UE. Although the direct testimony of Company witness Borkowski (p. 9) discusses the use of an updated transmission plant allocation factor as of January 1, 2006, AmerenUE did not recognize the coincident peak allocation factor change, as of June 2006, to allocate Schedule 10 costs for all pro forma test year months. Presumably, the Company will agree to recognize this known and measurable change in the allocation factor and will revise O&M Adjustment #10 accordingly.

Q. Do you have any further comments regarding UE's O&M Adjustment #10 or O&M Adjustment #11?

A. Yes. Beginning at the bottom of page 20 of his supplemental direct testimony, Company witness Weiss recommends that O&M Adjustment #11 be updated to recognize actual MISO power market fees through December 31, 2006, for consistency with the update proposed for O&M Adjustment #3. Because Company O&M Adjustment #10 recognizes a mix of actual and budget monthly amounts in 2006 to determine pro forma MISO Day 1 transmission costs, the State also recommends that O&M Adjustment #10 be updated to

[37] AmerenUE responses to Data Requests AG/UTI-131 (highly confidential), AG/UTI-132 and AG/UTI-196.

reflect actual 2006 MISO costs, as adjusted to recognize the June 2006 coincident peak allocation factor for all applicable 2006 amounts.

INTEREST SYNCHRONIZATION

Q. Please describe State Adjustment C-21.

A. State Adjustment C-21 synchronizes the interest deduction for income tax purposes with the State's proposed weighted cost of debt and rate base recommendations. This method of annualizing interest expense is commonly referred to as interest synchronization.

Q. Please define interest synchronization.

A. Interest synchronization is a method which provides for the allocation of an interest expense deduction for income tax purposes to ratepayers equal to the ratepayers' contribution to the Company for interest expense, regardless of the Company's actual or estimated interest payments to its creditors. Since revenue requirement is partially driven by the application of a rate of return to the rate base investment, the Company will recover from its ratepayers an amount of interest expense equal to the effective weighted cost of debt embedded in that rate of return. Thus, ratemaking interest can be quite different from the actual interest expense which might otherwise be deductible on a company's consolidated or stand-alone corporate tax return. Interest synchronization merely "synchronizes" the ratemaking tax deduction for interest with the interest expense ratepayers are required to provide the Company in utility rates.

Q. Did the Company propose the use of interest synchronization in quantifying its pro forma level of income tax expense?

A. Yes. Although Company witness Weiss does not specifically discuss interest synchronization in his supplemental direct testimony, UE Schedule GSW-E32 does apply this approach in quantifying the amount of deductible "interest on debt" in arriving at the amount of taxable income used to calculate pro forma income tax expense. More specifically, the referenced Company workpaper contains a footnote that generally describes the use of the interest synchronization methodology.

Q. If AmerenUE employed interest synchronization, why is it necessary for the State to separately quantify an adjustment for interest synchronization?

A. Had the State concurred in the Company's valuation of both rate base and cost of capital, a separate adjustment for interest synchronization would not have been necessary. However, when the State proposes, or the Commission ultimately orders, a different valuation of rate base or the weighted cost of debt, it is necessary to quantify the pro forma effect of such differences on overall revenue requirement. Since the State has quantified the income tax expense consequences associated with of each proposed income statement adjustment, the State has quantified a separate incremental adjustment to recognize the impact of changes in rate base and the capital structure on the ratemaking deduction for interest expense. In the event that the Commission ultimately adopts rate base and/or capital cost valuations other than those presented by either the State or the Company, interest synchronization should be recalculated using the Commission's findings, thereby appropriately synchronizing these revenue requirement elements. Consequently, the amount of pro forma interest expense ultimately recognized for ratemaking purposes should simply "roll out" from the Commission's ultimate decisions on allowable values of jurisdictional rate base and weighted cost of debt.

INCOME TAXES, UNCOLLECTIBLES & REVENUE CONVERSION FACTOR

Q. What is the purpose of this portion of your testimony?

A. Because of the manner in which the Company chose to present its calculation of overall revenue requirement in this proceeding, it was necessary for certain elements of UE's filed amounts to be recalculated for presentation in the format set forth in the State Joint Accounting Schedules. First, during the review of the Company's calculation of overall revenue requirement, it was determined that AmerenUE had not prepared a calculation of pro forma, adjusted operating results before recognizing the claimed revenue deficiency.[38] Consequently, it was necessary to recalculate the amount of operating revenue and income tax expense included the Company pro forma column of State Schedule C in order to exclude AmerenUE's requested rate increase.

Second, it was determined that the Company's calculation of the overall revenue deficiency on Schedules GSW-E36 and GSW-E37 include a gross-up for uncollectibles using a rate of .56%. In order to clearly show this treatment of uncollectibles in the calculation of overall revenue requirement, State Schedule A-1 recognizes this .56%

[38] A review of the revenue requirement schedules appended to the supplemental direct testimony of Company witness Weiss revealed that UE did not provide a calculation of adjusted net operating income <u>before</u> the inclusion of the claimed revenue deficiency in operating revenues. Specifically, the calculations set forth on UE Schedules GSW-E32 (income taxes), GSW-E36 and GSW-E37 (revenue requirement) include the effects of the Company's proposed rate increase.

uncollectible rate in calculating the revenue conversion factor of 1.632217 that is then carried forward and applied on State Schedule A.

Finally, after the various calculations noted above, the overall revenue deficiency of $374.748 million set forth on State Schedule A, Column C, Line 7, generally agrees with the $374.749 million operating revenue deficiency presented on UE Schedule GSW-E37.[39]

Q. In quantifying overall revenue requirement, State Schedules A and A-1 show two different "revenue conversion factors" for translating the operating income deficiency into the gross revenue requirement. The conversion factor for UE is 1.632217 while the State proposes a factor of 1.623077. Could you explain the difference between these two calculated revenue conversion factors?

A. Yes. The sole difference between these two conversion factors is attributable to the Company's proposal to gross up the overall revenue deficiency to recover additional uncollectibles attributed to the requested rate increase of almost $375 million. The effect of this Company proposal increases the Company's proposed revenue requirement by about $2.1 million.[40]

[39] The $1,000 difference between these amounts is due to rounding.

[40] Referring to UE Schedule GSW-E37, the Net Revenue Requirement After Uncollectible Expense is $2,391,238,000 as compared to the Net Revenue Requirement (i.e., before uncollectibles) is $2,389,139,000, representing a difference of $2,099,000.

Q. Referring to State Schedules A and A-1, would it be accurate to state that it is the recommendation of the State that uncollectibles be excluded from the revenue conversion factor in quantifying overall revenue requirement?

A. Yes. In a separate testimony section, I discuss recent historical data regarding the relationship between operating revenues and net write-offs of uncollectible accounts. Based on this information, I recommend that uncollectibles are properly excluded from the revenue conversion factor.

CAPITAL STRUCTURE

Q. Could you identify the capital structure and cost rates proposed by the State?

A. Yes. State Schedule D sets forth the capital structure and cost rates recommended by both UE and the State, including the return on equity and debt cost rates recommended by State witness Woolridge. For purposes of the State's direct testimony, Schedule D employs the capital structure ratios contained in the Company's supplemental filing of September 29, 2006.

Q. Is the State's proposed weighted cost of capital consistent with the test year approach used in quantifying the other components of the ratemaking formula?

A. Yes, I believe so. I am not aware of any material changes to the recorded financial data that would cause the proposed capital structure to materially distort overall revenue requirement associated with the planned update through January 1, 2007.

Q. Does the Commission's Procedural Order envision that the State, Staff and other parties will have the opportunity to review and, if necessary, respond to any capital structure update the Company might propose?

A. Yes. Pages 5-6 of the Procedural Order specify that the Company will file its proposed true-up data on March 2, 2007, with all parties submitting direct and rebuttal true-up testimonies on April 6 and April 13, 2007, respectively. To the extent that the Company's proposed updates have the effect of introducing test year distortions into the ratemaking process, the parties should have a reasonable opportunity to respond to any such proposals in their respective update testimony.

Q. Should the fact that the State employed UE's June 2006 capital structure ratios and non-equity cost rates for its direct filing be interpreted as any acquiescence, acceptance or adoption of the any update the Company might file on March 2, 2007?

A. No. The State intends to review UE's update filing, including proposed changes in the capital structure and cost rates. Any unanticipated capital structure or cost rate issues that might arise will be addressed at that time.

PENSION & OPEB TRACKING MECHANISM

Q. On September 19, 2006, AmerenUE filed the Supplemental Direct Testimony of C. Kenneth Vogl. Beginning on page 2 of that testimony, Mr. Vogl modifies a regulatory tracking mechanism, initially proposed in his direct testimony, to account for changes in pension and other postretirement benefit costs. Have you reviewed this testimony?

A. Yes. I have reviewed both Mr. Vogl's original and supplemental direct testimony on this subject, as well as Schedule CKV-E2-1 attached to his supplemental testimony. Schedule CKV-E2-1 actually sets forth the manner in which Mr. Vogl envisions that the proposed tracking mechanism would work.

Q. Could you briefly explain the intended purpose underlying the proposed tracking mechanism?

A. Yes. As summarized at page 20 of his original direct testimony, Mr. Vogl states:

> AmerenUE is proposing to establish a procedure that will ensure the amounts collected from ratepayers for pensions and OPEBs are the same as the costs it recognizes for shareholder reporting purposes and funds to the plan. The proposed procedure will accomplish this, and ratepayers will neither be undercharged nor overcharged for these costs. Without such a procedure, these largely uncontrollable and volatile increases or decreases in AmerenUE's costs that occur between rate cases will never be reflected in the rates paid by its customers.

I concur with Mr. Vogl that pension costs and OPEB costs have been extremely volatile over the years, with some utilities even recording <u>negative</u> pension costs for a period of time. It is also true, as implied by the above quote, that there has been a general disconnect between the pension (and OPEB) costs included in setting utility rates <u>from</u> the pension (and OPEB) costs a utility records and reports for financial statement disclosure purposes <u>from</u> the utility's actual contributions to its external pension (and OPEB) trust fund. While each of these elements may (or may not) be synchronized during a particular utility rate case, the significant volatility that arises between utility rate cases has often resulted in the presentation of complex ratemaking issues is utility rate cases.

Q. Are you generally familiar with those complex rate case issues?

A. Yes. Some jurisdictions have committed significant resources to evaluate, adjust and modify various assumptions (e.g., discount rate, assumed return on plan assets, amortization of gains and losses, etc.) included in the actuarial studies used to determine annual costs recorded by the utility and recognized in operating expense. Regulators in other jurisdictions have also expended significant resources evaluating the reasonableness of utility claims that a pension (or OPEB) asset or liability should be recognized in rate base.

Over the years, I have sponsored testimony in various jurisdictions addressing utility requests to include a prepaid pension asset in rate base, including:

Jurisdiction	Case / Docket	
Arizona Corporation Commission	E-1051-93-183	(a)
	T-1051B-99-105	(a)
	T-1051B-03-0454	(b)
Public Utilities Commission of Hawaii	94-0298	(d)
	04-0113	(e)
Oklahoma Corporation Commission	PUD 001151	(f)
Utah Public Service Commission	97-049-08	(a)
Washington Utilities & Transportation Commission	UT-930074	(c)
	UT-040788	(g)

Note (a): Qwest Corp. rate case.
Note (b): Qwest Corp. price cap review
Note (c): Qwest Corp. AFOR – sharing.
Note (d): GTE Hawaiian Tel.
Note (e): Hawaiian Electric Co.
Note (f): Oklahoma Natural Gas.
Note (g): Verizon Northwest rate case.

In most of these dockets, the prepaid pension asset the utility sought to include in rate base arose as a result of normal pension cost accounting – not because the utility was out-of-pocket for the "asset" balance. Rather than delve into the complexities of the prepaid pension asset debate, let me just say that the crux of that debate is directly linked to differences in the amount of pension (and OPEB) costs included in rates from the pension (and OPEB) costs a utility records and reports for financial statement disclosure purposes from the utility's actual contributions to its external pension (and OPEB) trust fund. The pension and OPEB tracking mechanism proposed by Mr. Vogl attempts to step around those inconsistencies so as to ensure that utility ratepayers do not over-pay or under-pay and the utility does not over-collect or under-collect pension (and OPEB) costs over time.

Q. Have any regulatory jurisdictions adopted a similar pension (and OPEB) tracking mechanism?

A. Yes. This Commission adopted a similar mechanism contained within a stipulation and agreement in a relatively recent rate case filed by Empire District Electric Company (Case No. ER-2004-0570).[41] While the specific terms and conditions may be subject to some modification in the pending rate case, the Kansas City Power and Light Company Experimental Regulatory Plan (Case No. EO-2005-0329) included a very similar pension tracking mechanism. However, each of these mechanisms is slightly different to account for the unique history and circumstances of each utility.

Q. Is the State opposing or proposing to materially modify the Company's proposed tracking mechanism?

[41] As confirmed by AmerenUE in response to Data Request AG/UTI-276, the AmerenUE tracking mechanism was designed by Mr. Vogl to be consistent with a similar mechanism set forth in a stipulation and agreement in the identified Empire District Electric Company ("EDE") rate case. Mr. Vogl had been retained by EDE in that proceeding and actively participated in the development the mechanism set forth in the referenced EDE stipulation and agreement.

A. No. After careful review and discussion with Mr. Vogl, I have concluded that the tracking mechanism is symmetrical, fair and equitable for both ratepayers and AmerenUE.[42]

Q. If the State is not opposing or modifying the Company's proposal, why have you prepared testimony discussing this issue?

A. Although the proposed tracking mechanism set forth in UE Schedule CKV-E2-1 is only three pages long and comprised of seven paragraphs, the mechanism is a relatively complex approach to resolve a complex regulatory issue. After discussing this mechanism in detail with Mr. Vogl, Schedule SCC-6 was prepared for the purpose of briefly discussing and clarifying certain elements of the mechanism set forth in UE Schedule CKV-E2-1.

Q. Does this conclude your direct testimony?

A. Yes.

[42] Schedule SCC-7 contains the responses of AmerenUE to Data Requests AG/UTI-276 through AG/UTI-283, which help to further clarify the operational mechanics of the Company's proposed tracking mechanism.

STEVEN C. CARVER
SUMMARY OF QUALIFICATIONS

Education and Experience

I graduated from State Fair Community College where I received an Associate of Arts Degree with an emphasis in Accounting. I also graduated from Central Missouri State University with a Bachelor of Science Degree in Business Administration, majoring in Accounting. Subsequent to the completion of formal education, my entire professional career has been dedicated to public utility investigations, regulatory analysis and consulting.

From 1977 to 1987, I was employed by the Missouri Public Service Commission in various professional auditing positions associated with the regulation of public utilities. In that capacity, I participated in and supervised various accounting compliance and rate case audits (including earnings reviews) of electric, gas and telephone utility companies and was responsible for the submission of expert testimony as a Staff witness.

In October 1979, I was promoted to the position of Accounting Manager of the Kansas City Office of the Commission Staff and assumed supervisory responsibilities for a staff of regulatory auditors, directing numerous rate case audits of large electric, gas and telephone utility companies operating in the State of Missouri. In April 1983, I was promoted by the Commission to the position of Chief Accountant and assumed overall management and policy responsibilities for the Accounting Department, providing guidance and assistance in the technical development of Staff issues in major rate cases and coordinating the general audit and administrative activities of the Department.

During 1986-1987, I was actively involved in a docket established by the Missouri Public Service Commission to investigate the revenue requirement impact of the Tax Reform Act of 1986 on Missouri utilities. In 1986, I prepared the comments of the Missouri Public Service Commission respecting the Proposed Amendment to FAS Statement No. 71 (relating to phase-in plans, plant abandonments, plant cost disallowances, etc.) as well as the Proposed Statement of Financial Accounting Standards for Accounting for Income Taxes. I actively participated in the discussions of a subcommittee responsible for drafting the comments of the National Association of Regulatory Utility Commissioners ("NARUC") on the Proposed Amendment to FAS

Statement No. 71 and subsequently appeared before the Financial Accounting Standards Board with a Missouri Commissioner to present the positions of NARUC and the Missouri Commission.

In July of 1983 and in addition to my duties as Chief Accountant, I was appointed Project Manager of the Commission Staff's construction audits of two nuclear power plants owned by electric utilities regulated by the Missouri Public Service Commission. As Project Manager, I was involved in the staffing and coordination of the construction audits and in the development and preparation of the Staff's audit findings for presentation to the Commission. In this capacity, I coordinated and supervised a matrix organization of Staff accountants, engineers, attorneys and consultants.

Since commencing employment with Utilitech in June 1987, I have conducted revenue requirement and special studies involving various regulated industries (i.e., electric, gas, telephone and water) and have been associated with regulatory projects on behalf of clients in twenty State regulatory jurisdictions.

Previous Expert Testimony

I have appeared as an expert witness before the Missouri Public Service Commission on behalf of various clients, including the Commission Staff. I have filed testimony before utility regulatory agencies in Arizona, California, Florida, Hawaii, Kansas, Indiana, Nevada, New Mexico, Oklahoma, Pennsylvania, Utah, and Washington. My previous experience involving electric and gas company proceedings includes: PSI Energy, Union Electric (now Ameren), Kansas City Power & Light, Missouri Public Service/ UtiliCorp United (now Aquila), Public Service Company of Oklahoma, Oklahoma Gas and Electric, Hawaii Electric Light, Hawaiian Electric, Sierra Pacific Power/ Nevada Power, Gas Service Company, Northern Indiana Public Service Company, Arkla (a Division of NORAM Energy), Oklahoma Natural Gas Company, Missouri Gas Energy and The Gas Company.

State Schedule SCC-2 summarizes various regulatory proceedings in which I have filed testimony.

STEVEN C. CARVER
Summary of Previously Filed Testimony
1978 through 2006 (December)

Utility	Jurisdiction	Agency	Docket/Case Number	Party Represented	Year	Areas Addressed
Kansas City Power & Light	Missouri	PSC	ER-78-252	Staff	1978	Rate Base, Operating Income
Gas Service Company	Missouri	PSC	GR-79-114	Staff	1979	Rate Base, Operating Income
United Telephone of Missouri	Missouri	PSC	TO-79-227	Staff	1979	Rate Base, Operating Income, Affiliated Interest
Kansas City Power & Light	Missouri	PSC	ER-80-48	Staff	1980	Operating Income, Fuel Cost
Gas Service Company	Missouri	PSC	GR-80-173	Staff	1980	Operating Income
Southwestern Bell Telephone	Missouri	PSC	TR-80-256	Staff	1980	Operating Income
Missouri Public Service	Missouri	PSC	ER-81-85	Staff	1981	Operating Income
Missouri Public Service	Missouri	PSC	ER-81-154	Staff	1981	Interim Rates
Gas Service Company	Missouri	PSC	GR-81-155	Staff	1981	Operating Income
Gas Service Company	Missouri	PSC	GR-81-257	Staff	1981	Interim Rates
Union Electric Company	Missouri	PSC	ER-82-52	Staff	1982	Operating Income, Fuel Cost
Southwestern bell Telephone	Missouri	PSC	TR-82-199	Staff	1982	Operating Income
Union Electric Company	Missouri	PSC	ER-83-163	Staff	1983	Rate Base, Plant Cancellation Costs
Gas Service Company	Missouri	PSC	GR-83-207	Staff	1983	Interim Rates
Union Electric Company	Missouri	PSC	ER-84-168/ EO-85-17	Staff	1984 1985	Construction Audit, Operating Income

STEVEN C. CARVER
Summary of Previously Filed Testimony
1978 through 2006 (December)

Utility	Jurisdiction	Agency	Docket/Case Number	Party Represented	Year	Areas Addressed
Kansas City Power & Light	Missouri	PSC	ER-85-128/ EO-85-185	Staff	1983 1985	Construction Audit, Rate Base, Operating Income
St. Joseph Light & Power	Missouri	PSC	EC-88-107	Public Counsel	1987	Rate Base, Operating Income
Northern Indiana Public Service	Indiana	IURC	38380	Consumer Counsel	1988	Operating Income
US West Communications	Arizona	ACC	E-1051-88-146	Staff	1989	Rate Base, Operating Income
Dauphin Consol. Water Supply Co.	Pennsylvania	PUC	R-891259	Staff	1989	Rate Base, Operating Income, Rate Design
Southwest Gas Corporation	Arizona	ACC	E-1551-89-102 E-1551-89-103	Staff	1989	Rate Base, Operating Income
Southwestern Bell Telephone	Missouri	PSC	TO-89-56	Public Counsel	1989 1990	Intrastate Cost Accounting Manual
Missouri Public Service	Missouri	PSC	ER-90-101	Public Counsel/ Staff	1990	UtiliCorp United Corporate Structure/ Diversification
City Gas Company	Florida	PSC	891175-GU	Public Counsel	1990	Rate Base, Operating Income, Acquisition Adjustment
Capital City Water Company	Missouri	PSC	WR-90-118	Jefferson City	1991	Rehearing - Water Storage Contract
Southwestern Bell Telephone Company	Oklahoma	OCC	PUD-000662	Attorney General	1991	Rate Base, Operating Income
Public Service of New Mexico	New Mexico	PSC	2437	USEA	1992	Franchise Taxes
Citizens Utilities Company	Arizona	ACC	ER-1032-92-073	Staff	1992 1993	Rate Base, Operating Income
Missouri Public Service Company	Missouri	PSC	ER-93-37	Staff	1993	Accounting Authority Order

STEVEN C. CARVER
Summary of Previously Filed Testimony
1978 through 2006 (December)

Utility	Jurisdiction	Agency	Docket/Case Number	Party Represented	Year	Areas Addressed
Public Service Company of Oklahoma	Oklahoma	OCC	PUD-1342	Staff	1993	Rate Base, Operating Income, Acquisition Adjustment
Hawaiian Electric Company	Hawaii	PUC	7700	Consumer Advocate	1993	Rate Base, Operating Income
US West Communications	Washington	WUTC	UT-930074, 0307	Public Counsel/ TRACER	1994	Sharing Plan Modifications
US West Communications	Arizona	ACC	E-1051-93-183	Staff	1994	Rate Base, Operating Income
PSI Energy, Inc.	Indiana	IURC	39584	Consumer Counselor	1994	Operating Income, Capital Structure
Arkla, a Division of NORAM Energy	Oklahoma	OCC	PUD-940000354	Attorney General	1994	Rate Base, Operating Income
Kauai Electric Division of Citizens Utilities Company	Hawaii	PUC	94-0097	Consumer Advocate	1995	Hurricane Iniki Storm Damage Restoration
Oklahoma Natural Gas Company	Oklahoma	OCC	PUD-940000477	Attorney General	1995	Rate Base, Operating Income
US West Communications	Washington	WUTC	UT-950200	Attorney General/ TRACER	1995	Rate Base, Operating Income
PSI Energy, Inc.	Indiana	IURC	40003	Consumer Counselor	1995	Rate Base, Operating Income
GTE Hawaiian Tel; Kauai Electric - Citizens Utilities Co.; Hawaiian Electric Co.; Hawaii Electric Light Co.; Maui Electric Company	Hawaii	PUC	PUC 95-0051	Consumer Advocate	1996	Self-Insured Property Damage Reserve

STEVEN C. CARVER
Summary of Previously Filed Testimony
1978 through 2006 (December)

Utility	Jurisdiction	Agency	Docket/Case Number	Party Represented	Year	Areas Addressed
GTE Hawaiian Telephone Co., Inc.	Hawaii	PUC	PUC 94-0298	Consumer Advocate	1996	Rate Base, Operating Income
Oklahoma Gas and Electric Company	Oklahoma	OCC	PUD-960000116	Attorney General	1996	Rate Base, Operating Income
Public Service Company	Oklahoma	OCC	PUB-0000214	Attorney General	1997	Rate Base, Operating Income
Arizona Telephone Company (TDS)	Arizona	ACC	U-2063-97-329	Staff	1997	Rate Base, Operating Income, Affiliate Transactions
US West Communications	Utah	UPSC	97-049-08	Committee of Consumer Services	1997	Rate Base, Operating Income
Missouri Gas Energy	Missouri	PSC	GR-98-140	Public Counsel	1998	Revenues, Uncollectibles
Sierra Pacific Power Company	Nevada	PUCN	98-4062 98-4063	Utility Consumers Advocate	1999	Sharing Plan
Hawaii Electric Light Co., Power Purchase Agreement (Encogen)	Hawaii	PUC	PUC 98-0013	Consumer Advocate	1999	Keahole CT-4/CT-5 AFUDC, Avoided Cost
Kansas City Power & Light Company	Missouri	MoPSC	EC-99-553	GST Steel Company	1999	Complaint Investigation
US West Communications	New Mexico	NM PRC	3008	PRC Staff	2000	Rate Base, Operating Income
Hawaii Electric Light Company	Hawaii	PUC	PUC 99-0207	Consumer Advocate	2000	Keahole pre-PSD Common Facilities
US West/ Qwest Communications	Arizona	ACC	T-1051B-99-105	Staff	2000	Rate Base, Operating Income
The Gas Company	Hawaii	PUC	00-0309	Consumer Advocate	2001	Rate Base, Operating Income, Nonreg Svcs.

STEVEN C. CARVER
Summary of Previously Filed Testimony
1978 through 2006 (December)

Utility	Jurisdiction	Agency	Docket/Case Number	Party Represented	Year	Areas Addressed
Craw-Kan Telephone Cooperative, Inc.	Kansas	KCC	01-CRKT-713-AUD	KCC Staff	2001	Rate Base, Operating Income
Home Telephone Company, Inc.	Kansas	KCC	02-HOMT-209-AUD	KCC Staff	2002	Rate Base, Operating Income
Wilson Telephone Company, Inc.	Kansas	KCC	02-WLST-210-AUD	KCC Staff	2002	Rate Base, Operating Income
SBC Pacific Bell	California	PUC	01-09-001 / 01-09-002	Office of Ratepayer Advocate	2002	New Regulatory Framework / Earnings Sharing Investigation
JBN Telephone Company	Kansas	KCC	02-JBNT-846-AUD	KCC Staff	2002	Rate Base, Operating Income
Kerman Telephone Company	California	PUC	02-01-004	Office of Ratepayer Advocate	2002	General Rate Case, Affiliate Lease, Nonregulated Transactions
S&A Telephone Company	Kansas	KCC	03-S&AT-160-AUD	KCC Staff	2003	Rate Base, Operating Income, Nonreg Alloc
PSI Energy, Inc.	Indiana	IURC	42359	Consumer Counselor	2003	Rate Base, Operating Income, Nonreg Alloc
Arizona Public Service Company	Arizona	ACC	E-10345A-03-0437	ACC Staff	2004	Rate Base, Operating Income
Qwest Corporation	Arizona	ACC	T-01051B-03-0454 & T-00000D-00-0672	ACC Staff	2004	Rate Base, Operating Income, Nonreg Alloc
Verizon Northwest Inc.	Washington	WUTC	UT-040788	Attorney General/ AARP/ WeBTEC	2004	Rate Base, Operating Income
Public Service Company	Oklahoma	OCC	PUD-200300076	Attorney General	2005	Operating Income
Hawaiian Electric Company	Hawaii	PUC	04-0113	Consumer Advocate	2005	Rate Base, Operating Income
Citizens Gas & Coke Utility	Indiana	IURC	42767	Consumer Counselor	2005	Operating Income, Benchmarking Study
AmerenUE d/b/a Union Electric Co.	Missouri	MoPSC	ER-2007-0002	State of Missouri	2006	Revenue Requirement

AmerenUE's Response to
State of MO - Atty General Data Request
MPSC Case No. ER-2007-0002
AmerenUE's Tariff Filing to Increase Rates for Electric Service
Provided to Customers in the Company's Missouri Service Area

Requested From: Mike Brosch

Data Request No. AG/UTI-049

Ref. Zdellar Supplemental Direct, p. 4 (New Vegetation Program). Mr. Zdellar briefly discusses four new programs designed to expand the Company's existing approach to vegetation management. Beginning at line 6, the first new vegetation management program is described as involving the expansion of the ¿tree removal program to include the targeted removal of problematic trees off of AmerenUE's rights-of-way and easements on private property, as well as significantly expanding our on right-of-way removal program.¿ Please provide the following:

a. Has AmerenUE identified or quantified the population of ¿problematic trees¿ located on private property, but outside the Company's rights-of-way or utility easements? Please explain.

b. Please explain and describe the process undertaken by the Company to evaluate the nature and extent of the exposure presented by such problematic trees to AmerenUE's plant and equipment.

c. Please describe the right-of-way removal program under the Company's existing vegetation management program.

d. Please provide a detailed explanation of the Company's plans to significantly expand the right-of-way removal program.

e. Is Commission approval required before AmerenUE can implement this new program?
Please explain.

Response:

A) At this time this in unknown.

B) Tree caused outages, as well as other outages causes, are recorded in Ameren's OAS (Outage Analysis System). There have been several national studies and articles published indicating that the majority of tree caused outages occur from off right-of-way trees.

C) In general, trees located directly under primary lines, requiring repeated trimming, should be removed if the cost of removal does not exceed that necessary to accomplish two trimming operations.

D) Initial focus will be on the three phase sections of circuits, with an expansion of the removal criteria to include more mature trees that typically have been trimmed on past cycles.

E) Yes, the recovery of additional expenses would be needed for AmerenUE to proceed along with the support of the Commission.

Prepared By: Ronald Zdellar

Title: VP Energy Delivery - Distribution Svc

Date: November 3, 2006

AmerenUE's Response to
State of MO - Atty General Data Request
MPSC Case No. ER-2007-0002
AmerenUE's Tariff Filing to Increase Rates for Electric Service
Provided to Customers in the Company's Missouri Service Area

Requested From: Mike Brosch

Data Request No. AG/UTI-050

Ref. Zdellar Supplemental Direct, p. 4 (New Vegetation Program). Beginning at line 9, the
discussion of the second new vegetation management program encompasses broadening
AmerenUE's ¿clearance requirements, especially on three-phase feeder sections, ... [increase]
side clearance, overhang removal, and tree crown reduction.¿ Please provide the following:
a. Does the Company's proposal to broaden clearance requirements, side clearance and overhang removal apply solely to its current areas of rights-or-way and private property easements or does AmerenUE plan to expand further onto public or private property? Please
explain.
b. Is Commission approval required before AmerenUE can implement this new program?
Please explain.

Response:

A) The broadening of side clearance and overhang removal may require that AmerenUE encroach upon public and private property in order to achieve desired clearances in accordance with trimming standards as stated in Ansi A300 specifically section 5.9 that relates to utility pruning. When trimming or pruning tree growth that encroaches upon facilities AmerenUE trims in accordance with acceptable trimming standards. This may require, similar to present practice, that the final pruning cut be made at a location in the tree that is not within the easement.

B) Yes, the recovery of additional expenses would be needed for AmerenUE to proceed along with the support of the Commission.

Prepared By: Ronald Zdellar

Title: VP Energy Delivery - Distribution Svc

Date: November 3, 2006

AmerenUE's Response to
State of MO - Atty General Data Request
MPSC Case No. ER-2007-0002
AmerenUE's Tariff Filing to Increase Rates for Electric Service
Provided to Customers in the Company's Missouri Service Area

Requested From: Mike Brosch

Data Request No. AG/UTI-051

Ref. Zdellar Supplemental Direct, p. 4 (New Vegetation Program). Beginning at line 14, the third new vegetation management program would further reduce the cycle lengths for a number of feeders from four years to three years. Please provide the following

a. What is the average length of tree growth in one year? Please explain.
b. What is the estimated cost of shortening the trimming cycle by one year? Please explain.
c. Has the Company determined that shortening the trimming cycle by one year will materially reduce storm damage to its transmission and distribution facilities? Please explain. .
d. Has the Company determined that shortening the trimming cycle by one year will materially enhance system reliability? Please explain.
e. Is Commission approval required before AmerenUE can implement this new program? Please explain.

Response:

A) The average length of tree growth in one year is determined by multiple factors some of which include: the tree species, specific age of the tree, specific health of the tree, specific environmental condition of the tree such as rain, fertilization etc., and the type and extensiveness of trimming performed. Even within the same species "the average length of tree growth" can vary for the above factors.

B) The cost of trimming varies by circuit. The cost of trimming any circuit is dependent on multiple factors, one of which is cycle length. If all other factors between cycles are identical, which is seldom the case, then the following for illustrative purpose would be: The annual maintenance cost of a feeder that takes $40, 000 to trim would be $10,000 on a four cycle and $13,333 on a three year cycle.

C) The anticipated result would be a further reduction in the frequency of tree caused interruptions during regularly experienced winds.

D) The anticipated result would be an improvement on tree related outages for regularly experience wind events, on the selective feeders that are reduced in cycle length.

E) Yes, the recovery of additional expenses would be needed for AmerenUE to proceed along with the support of the Commission.

Prepared By: Ronald Zdellar

Title: VP Energy Delivery - Distribution Svc

Date: November 3, 2006

AmerenUE's Response to
State of MO - Atty General Data Request
MPSC Case No. ER-2007-0002
AmerenUE's Tariff Filing to Increase Rates for Electric Service
Provided to Customers in the Company's Missouri Service Area

Requested From: Mike Brosch

Data Request No. AG/UTI-052

Ref. Zdellar Supplemental Direct, p. 4 (New Vegetation Program). Beginning at line 17, the fourth new vegetation management program is described as follows: ¿we propose to increase our tree replacement program with municipalities. The program is currently limited in scope, but going forward we would propose to increase this effort more than fourfold, to target municipal trees for removal and/or replacement, thus reducing the risk of future potential outages.¿
Please provide the following:
a. For each of the fiscal years ended June 30th during the period 2004-2006, please provide the amount the Company has expended to remove and/or replace municipal trees.
b. To what extent has the damage to the Company's transmission and distribution facilities been caused by trees owned by municipalities versus trees owned by non-municipal (i.e., residential, commercial or industrial) customers?
c. Does the Company currently replace trees owned by non-municipal entities (e.g., residential, commercial or industrial customers)? Please explain.
d. Does the Company plan to increase its replacement of trees owned by non-municipal entities (e.g., residential, commercial or industrial customers)? Please explain.
e. Is Commission approval required before AmerenUE can implement this new program?
Please explain.

Response:

A) The expenditures to the municipals for compensation only for fiscal year ending June 30th, 2004 is $400, for June 30th, 2005 is $4000, and for June 30th, 2006 is $1200. Note that since this is considered as one component of the Tree Replacement Program these expenditures were included in DR AG-UTI-039 part E. Expenditures do not include cost of actual tree removals with vendors, which in the past has typically been included in the total cost of the circuit.

B) This is unknown and presently not tracked on ownership.

C) Yes, this is explained in DR AG-UTI-039 part D.

D) Yes under the stated goal of DR AG-UTI-039 part B.

E) Yes, the recovery of additional expenses would be needed for AmerenUE to proceed along with the support of the Commission.

Prepared By: Ronald Zdellar

Title: VP Energy Delivery - Distribution Svc

Date: November 3, 2006

AmerenUE's Response to
State of MO - Atty General Data Request
MPSC Case No. ER-2007-0002
AmerenUE's Tariff Filing to Increase Rates for Electric Service
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Requested From: Mike Brosch

Data Request No. AG/UTI-054

Ref. Zdellar Supplemental Direct, p. 5 (New Vegetation Program). At lines 13-18, Mr. Zdellar states that these new programs will not prevent future storm-related outages, but indicates that they should reduce any vegetation damage that does occur to the Company's system during a storm. Have any cost/benefit studies or probabilistic studies been prepared by, or for, AmerenUE in this regard? If so, please provide a copy of each such study. If not, please explain.

Response:

No cost/benefit studies or probabilistic studies have been prepared by, or for, AmerenUE in regards to proposed new vegetation programs affect on major storm-related outages. However, data analysis on tree caused outages occurring outside of major storm event's, indicated the potential new vegetation programs could be effective.

Prepared By: Ronald Zdellar

Title: VP Energy Delivery – Distrib Svc

Date: November 27, 2006

AmerenUE's Response to
State of MO - Atty General Data Request
MPSC Case No. ER-2007-0002
AmerenUE's Tariff Filing to Increase Rates for Electric Service
Provided to Customers in the Company's Missouri Service Area

Requested From: Mike Brosch

Data Request No. AG/UTI-055

Ref. Zdellar Supplemental Direct, p. 5 (New Vegetation Program). Beginning at line 20, Mr.
Zdellar states: ¿If the Commission approves the new programs, we will begin phasing them into our enhanced vegetation management program immediately.¿ Please provide the following:
a. Please provide a detailed explanation of how the Company plans to phase in the new programs.
b. Assuming Commission approval of the new programs as requested by AmerenUE, how long does the Company believe that it will take for those the new programs to materially reduce potential storm damage and improve overall system reliability? Please explain.

Response:

A) The initial focus of the program will be predominantly in urban settings and initially involve the backbone sections of circuits.

B) Tree trimming is only one component of overall system reliability. The anticipated result will be a further reduction of tree caused customer interruptions during regularly experienced winds as the circuits are completed.

Prepared By: Ron Zdellar
Title: VP Energy Delivery – Distrib Svc
Date: November 6, 2006

AmerenUE's Response to
State of MO - Atty General Data Request
MPSC Case No. ER-2007-0002
AmerenUE's Tariff Filing to Increase Rates for Electric Service
Provided to Customers in the Company's Missouri Service Area

Requested From: Mike Brosch

Data Request No. AG/UTI-048

Ref. Zdellar Supplemental Direct, pp. 4-5 (New Vegetation Program). Mr. Zdellar generally discusses four new programs proposed by AmerenUE to expand its existing approach to vegetation management, at an incremental cost of $15 million. Please provide a detailed breakdown of the $15 million between each of the four identified new programs.

Response:

AmerenUE has proposed the additional $15 million for the four identified programs. The process to document and track is under discussion with MPSC staff and unknown at this time. The majority of the new expenditures will relate to removals on/off right-of-way and additional clearance to begin with, primarily on the three phase section of circuits.

Prepared By: Ronald Zdellar

Title: VP Energy Delivery - Distribution Svc

Date: November 3, 2006

AmerenUE's Response to
State of MO - Atty General Data Request
MPSC Case No. ER-2007-0002
AmerenUE's Tariff Filing to Increase Rates for Electric Service
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Requested From: Mike Brosch

Data Request No. AG/UTI-053

Ref. Zdellar Supplemental Direct, p. 5 (New Vegetation Program). Beginning at line 8, Mr. Zdellar refers to the incremental $15 million for these new programs and states: ¿AmerenUE would propose to keep this amount in a separately tracked account, and will apply interest to the balance,.to guarantee that these dollars will only be used to pay for the new programs identified
above.¿ Please provide the following:
a. What rate of interest does AmerenUE propose be applied to the balance in this tracking account?
b. Please provide a multi-year, illustrative example showing how the Company would track and apply interest to the account balance.

Response:

A). For the new vegetation programs see the attached file labeled AmerenUE Mo Case ER-2007-0002 AG-UTI DR 53.xls. This approach is one of several options that continue to be explored.

B) See A) above.

Prepared By: Ron Zdellar
Title: VP Energy Delivery – Distribution Svc.
Date: November 7, 2006

AmerenUE
MPSC Case No. ER-2007-0002
Monthly Allocation of $15 Million Additional Tree Removal Program

Month	Amount
June	$ 2,250,000
July	2,250,000
August	2,250,000
September	2,250,000
October	750,000
November	750,000
December	750,000
January	750,000
February	750,000
March	750,000
April	750,000
May	750,000
	$ 15,000,000

Note: Per Direct Testimony of Wilbon Cooper 60% of distribution cost recovered in 4 summer months and 40% recovered in 8 winter months.

Assuming that the order states that AmerenUE would receive recovery in its rates of $15 million annually for its new vegetation programs and AmerenUE has committed to spend the $15 million annually or carryover the unused portion with interest, the following accounting would apply.

Accounting Literature: FAS 71 - *Accounting for the Effects of Certain Types of Regulation* - Par. 11

b. A regulator can provide current rates intended to recover costs that are expected to be incurred in the future with the understanding that if those costs are not incurred future rates will be reduced by corresponding amounts. If current rates are intended to recover such costs and the regulator requires the enterprise to remain accountable for any amounts charged pursuant to such rates and not yet expended for the intended purpose, the enterprise shall not recognize as revenues amounts charged pursuant to such rates. Those amounts shall be recognized as liabilities and taken to income only when the associated costs are incurred.

AmerenUE would record monthly cash/accounts receivable with an increase to a Regulatory Liability as customers are billed based on the above schedule.

AmerenUE would decrease the Regulatory Liability as dollars were spent on the the new vegetation programs. In addition, AmerenUE would recognize revenues and an offsetting O&M expense in the month that the new programs were spent.

AmerenUE would record interest expense at the end of the year on any unused balance in the Regulatory Liability and increase the Regulatory Liability by the interest amount. Interest will be calculated using the Company's short-term borrowing rate.

State Comments & Clarification
Regarding AmerenUE Proposed Tracking Procedure
[UE Schedule CKV-E2-1]

1. The proposed tracking mechanism uses the words "cost" and "expense" interchangeably, both of which are intended to represent actuarially determined total FAS87 (or FAS106) net periodic costs.
2. The words "cost" and "expense" represent total actuarially determined amounts without regard to any allocation or capitalization accounting the Company may recognize on its books and records.
3. The proposed tracking mechanism requires the Company to make annual fund contributions in an amount equal to the total FAS87 (or FAS106) net periodic costs determined for each calendar year.
4. The proposed tracking mechanism requires the Company to establish a regulatory pension (or OPEB) asset or liability for the difference between the total FAS87 (or FAS106) net periodic costs determined for a given year and the amount of such costs included in then-existing utility rates.
5. The provisions of FAS87 and FAS106 may require a company to record a prepaid pension (or OPEB) asset in the normal course of business, without regard to any regulatory agreements or orders adopting a tracking mechanism:
    a. The proposed tracking mechanism would exclude from rate base for ratemaking purposes any prepaid pension (or OPEB) asset resulting from an actuarial study that resulted in "negative" net periodic costs.

b. The proposed tracking mechanism would exclude, or not recognize, any "negative" net periodic costs for ratemaking purposes, instead setting the amount equal to $0.

6. Even though AmerenUE is only allocated a portion of the FAS87 (and FAS106) net periodic costs associated with Ameren Services (AMS), if the funding mechanism is approved by the Commission, the Company has committed to funding 100% of the FAS87 (and FAS106) net periodic costs for both AmerenUE and AMS in order to avoid any funding conflicts or issues that might arise in the future.

7. The commitment to fund 100% of the FAS87 (and FAS106) net periodic costs for AMS was not contingent on approval of a substantially similar tracking mechanism by the other regulatory jurisdictions in which AmerenUE affiliates operate.

8. Regarding paragraph 6 of UE Schedule CKV-E2-1, AmerenUE does not actually "receive reimbursement for" but actually recovers its FAS87 and FAS106 costs through utility rates.

AmerenUE's Response to
State of MO - Atty General Data Request
MPSC Case No. ER-2007-0002
AmerenUE's Tariff Filing to Increase Rates for Electric Service
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Requested From: Steven Carver

Data Request No. AG/UTI-276

Ref. Vogi Supplemental Direct, Schedule CKV-E2-3 (FAS87 & FAS106 Tracking Mechanism). On Tuesday, 11/28/06, the referenced proposed tracking mechanism was discussed with Mr. Vogl. Please provide the following information:

a. Please confirm that the proposed AmerenUE tracking mechanism was designed by Mr. Vogi to be consistent with a similar mechanism set forth in a stipulation and agreement in a recent Empire District Electric Company (EDE) rate case, Case No. ER- 2004-0570. If this cannot be confirmed, please explain.

b. Please confirm that Mr. Vogi had been retained by EDE in Case No. ER-2004-0570 and participated in the development the mechanism set forth in the referenced stipulation and agreement. If this cannot be confirmed, please explain.

Response:

a. Yes, it was designed to be essentially the same as the tracking mechanism in the EDE case with some exceptions such as language to address the impact of FASB 158, inclusion of FAS 106 costs, and any EDE specific language that applied directly to EDE.

b. Yes, I was retained.

Prepared By: C. Kenneth Vogi

Title: Principal

Date: December 13, 2006

AmerenUE's Response to
State of MO - Atty General Data Request
MPSC Case No. ER-2007-0002
AmerenUE's Tariff Filing to Increase Rates for Electric Service
Provided to Customers in the Company's Missouri Service Area

Requested From: Steven Carver

Data Request No. AG/UTI-277

Ref. Vogi Supplemental Direct, Schedule CKV-E2-3 (FAS87 & FAS106 Tracking Mechanism). On Tuesday, 11/28/06, the referenced proposed tracking mechanism was discussed with Mr. Vogl. Please confirm that the FAS87 (and FAS106) actuarial studies, underlying the stipulated EDE tracking mechanism and the mechanism proposed by AmerenUE, incorporate the following considerations, specifically explaining each item that cannot be confirmed:

a. Use of Market Related Value for asset determination (EDE: 5 years; UE: 4 years);
b. No 10% corridor; and
c. 10 year amortization of unrecognized gains and losses.

Response:

a. Yes

b. Yes

c. Yes

Prepared By: C. Kenneth Vogi

Title: Principal

Date: December 13, 2006

AmerenUE's Response to
State of MO - Atty General Data Request
MPSC Case No. ER-2007-0002
AmerenUE's Tariff Filing to Increase Rates for Electric Service
Provided to Customers in the Company's Missouri Service Area

Requested From: Steven Carver

Data Request No. AG/UTI-278

Ref. Vogi Supplemental Direct, Schedule CKV-E2-3 (FAS87 & FAS106 Tracking Mechanism). On Tuesday, 11/28/06, the referenced proposed tracking mechanism was discussed with Mr. Vogl. Please provide the following information:

a. Please confirm that the proposed tracking mechanism uses the words "cost" and "expense" interchangeably, both of which are intended to represent actuarially determined total FAS87 (or FAS106) net periodic costs.

b. Referring to part (a) above, please confirm that "cost" and "expense" represent total actuarially determined amounts without regard to any allocation or capitalization accounting the Company may recognize on its books and records. If this cannot be confirmed, please explain.

c. Please confirm that the intent of the proposed tracking mechanism requires the Company to make annual fund contributions in an amount equal to the total FAS87 (or FAS106) net periodic costs determined each year. If this cannot be confirmed, please explain.

Response:

a. Yes, cost and expense are used interchangeably in the description of the tracking mechanism.

b. Yes, it should represent total expense.

c. Yes, the intent is to make annual contributions to the trusts equal to the total FAS 87 and FAS 106 expense amounts. There may be special cases (e.g. if the minimum required contribution under IRC 412 is greater than the total FAS 87 amount) where the annual contribution and the total FAS 87 amount are different.

Prepared By: C. Kenneth Vogi

Title: Principal

Date: December 13, 2006

AmerenUE's Response to
State of MO - Atty General Data Request
MPSC Case No. ER-2007-0002
AmerenUE's Tariff Filing to Increase Rates for Electric Service
Provided to Customers in the Company's Missouri Service Area

Requested From: Steven Carver

Data Request No. AG/UTI-279

Ref. Vogi Supplemental Direct, Schedule CKV-E2-3 (FAS87 & FAS106 Tracking Mechanism). On Tuesday, 11/28/06, the referenced proposed tracking mechanism was discussed with Mr. Vogl. Please provide the following information:

a. Please confirm that the proposed tracking mechanism would require the Company to establish a regulatory pension (or OPES) asset or liability for the difference between the total FAS87 (or FAS1 06) net periodic costs determined for a given year and the amount of such costs included in then-existing utility rates. If this cannot be confirmed, please explain.

b. The provisions of FAS87 and FAS106 may require a company to record a prepaid pension (or OPES) asset in the normal course of business, without regard to any regulatory agreements or orders adopting a tracking mechanism. Please provide the following:

i. Please confirm that the proposed tracking mechanism would exclude from rate base for ratemaking purposes any prepaid pension (or OPES) asset resulting from an actuarial study that resulted in "negative" net periodic costs. If this cannot be confirmed, please explain.

ii. Please confirm that the proposed tracking mechanism would exclude any "negative" net periodic costs for ratemaking purposes, instead setting the amount equal to $0. If this cannot be confirmed, please explain.

Response:

a. Yes.

bi. Yes, as described in the tracking mechanism, a prepaid pension (or OPES) asset created by negative pension (or OPES) expense will be tracked by a regulatory liability which is not a cash item and therefore will not impact rate base.

bii. Yes, the minimum amount to be built into rates for ongoing pension and OPES costs is zero.

Prepared By: C. Kenneth Vogi

Title: Principal

Date: December 13, 2006

AmerenUE's Response to
State of MO - Atty General Data Request
MPSC Case No. ER-2007-0002
AmerenUE's Tariff Filing to Increase Rates for Electric Service
Provided to Customers in the Company's Missouri Service Area

Requested From: Steven Carver

Data Request No. AG/UTI-280

Ref. Vogi Supplemental Direct, Schedule CKV-E2-3 (FAS87 & FAS1 06 Tracking Mechanism). On Tuesday, 11/28/06, the referenced proposed tracking mechanism was discussed with Mr. Vogl. Please provide the following:

a. Please confirm that AmerenUE is only allocated a portion of the FAS87 (and FAS106) net periodic costs associated with Ameren Services (AMS). If this cannot be confirmed, please explain.

b. Please confirm that it was unclear at the time of the meeting whether there were separate, non-commingled, pension and OPES funds to which contributions aree made on behalf of AmerenUE and AMS. If this cannot be confirmed, please explain.

c. Please confirm that, if the funding mechanism is approved by the Commission, the Company has committed to funding 100% of the FAS87 (and FAS1 06) net periodic costs for both AmerenUE and AMS. If this cannot be confirmed, please explain.

d. Referring to part (c) above, please confirm that the commitment to fund 100% of the FAS87 (and FAS1 06) net periodic costs for AMS was not contingent on approval of a substantially similar tracking mechanism by the other regulatory jurisdictions in which AmerenUE affiliates operate. If this cannot be confirmed, please explain.

Response:

a. I confirmed with Gary Weiss that AmerenUE is only allocated a portion of the FAS 87 (and FAS 106) net periodic costs associated with Ameren Services (AMS).

b. Yes, at the time of our meeting, I could not recall the structure of the pension and OPES trusts.

c. Yes, in order to track the costs and reimbursement correctly, the Company will be required to fund 100% of the total FAS 87 and FAS 106 costs for AmerenUE and AMS.

d. Yes, the requirement to fund is not contingent on any other event.

Prepared By: C. Kenneth Vogi

Title: Principal

Date: December 13, 2006

AmerenUE's Response to
State of MO - Atty General Data Request
MPSC Case No. ER-2007-0002
AmerenUE's Tariff Filing to Increase Rates for Electric Service
Provided to Customers in the Company's Missouri Service Area

Requested From: Steven Carver

Data Request No. AG/UTI-281

Ref. Vogi Supplemental Direct, Schedule CKV-E2-3 (FAS87 & FAS106 Tracking Mechanism). On Tuesday, 11/28/06, the referenced proposed tracking mechanism was discussed with Mr. Vogl, including various examples to illustrate how the mechanism would apply to certain circumstances. [Assume: Base rates include $40 million of FAS87 (or FAS106) net periodic costs and in the next year the required minimum contribution was $40 million and FAS87 (or FAS106) net periodic costs were $40 million.] Please provide the following:

a. Please confirm that the Company would make a fund contribution of $40 million, an amount equal to the FAS87 (and FAS106) net periodic costs. If this cannot be confirmed, please explain.

b. Please confirm that no regulatory asset or liability would be recorded because FAS87 (and FAS106) net periodic costs (i.e., $40 million) are equal to the amount included in base rates (i.e., $40 million). If this cannot be confirmed, please explain.

Response:

a. Yes.

b. Yes.

Prepared By: C. Kenneth Vogi
Title: Principal
Date: December 13, 2006

AmerenUE's Response to
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Ref. Vogi Supplemental Direct, Schedule CKV-E2-3 (FAS87 & FAS1 06 Tracking Mechanism). On Tuesday, 11/28/06, the referenced proposed tracking mechanism was discussed with Mr. Vogl, including various examples to illustrate how the mechanism would apply to certain circumstances. [Assume: Base rates include $40 million of FAS87 (or FAS106) net periodic costs and in the next year the required minimum contribution was $40 million and FAS87 (or FAS106) net periodic costs were $30 million.] Please provide the following:
a. The Company would make a fund contribution of $40 million. If this cannot be confirmed, please explain.
b. The Company would record a prepaid pension (or OPEB) asset of $10 million for the difference between the amount contributed and net periodic costs. If this cannot be confirmed, please explain.
c. The Company would record an offsetting regulatory liability of $10 million for the difference between the net periodic costs included in base rates ($40 million) and the amount of net periodic costs in the next year ($30 million). If this cannot be confirmed, please explain.
d. Although the Company recorded a prepaid pension (or OPEB) asset in the next year, this amount is offset by the regulatory liability so that zero dollars would be includable in rate base. If this cannot be confirmed, please explain.

Response:

a. Yes.

b. Yes, the company would create a prepaid asset of $10 million since contributions exceeded expense by that amount.

c. Yes.

d. Not exactly. The regulatory liability ($10 million) represents funds collected in rates ($40 million) that were not expensed/funded (Le., $30 million of expense and the first $30 million of contributions), therefore this regulatory liability is a cash item that will reduce rate base and be amortized over 5 years in favor of the rate payers. The additional $10 million in contributions which created the prepaid asset should be treated as a credit towards future contributions that would otherwise be required under this tracking method. For example, if the following year's pension expense is $40 million, then the Company would apply the prior year's credit of $10 million resulting in a $30 million contribution. The net result after two years would be $80 million collected in rates, $70 million expensed and funded to the trusts, and a $10 million regulatory liability. Note that the prepaid asset created by funding in excess of the total expense for the year will only impact rates if it hasn't been reduced to zero by the next rate case, and in that event it would only be included in rate base. No explicit amortization of the prepaid asset is required.

Prepared By: C. Kenneth Vogi

Title: Principal

Date: December 13, 2006

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Requested From: Steven Carver

Data Request No. AG/UTI-283

Ref. Vogi Supplemental Direct, Schedule CKV-E2-3 (FAS87 & FAS1 06 Tracking Mechanism). On Tuesday, 11/28/06, the referenced proposed tracking mechanism was discussed with Mr. Vogl, including various examples to illustrate how the mechanism would apply to certain circumstances. [Assume: Base rates include $40 million of FAS87 (or FAS1 06) net periodic costs and in the next year the required minimum contribution was $0 million and FAS87 (or FAS106) net periodic costs were negative $10 million.] Please provide the following

a. Please confirm that the Company would make a fund contribution of $0. If this cannot be confirmed, please explain.

b. The Company would record a prepaid pension (or OPEB) asset of $10 million for the difference between the amount contributed ($0) and net periodic costs for the current year (negative $10 million). If this cannot be confirmed, please explain.

c. Because the negative net periodic costs are non-cash under the tracking mechanism, the prepaid pension (or OPEB) asset referenced in part (b) is not recognized for rate base purposes. If this cannot be confirmed, please explain.

d. The Company would record a $40 million regulatory liability for the difference between the net periodic costs included in base rates (Le., $40 million) and the next year FAS87 (and FAS106) net periodic costs of $0, as required under the proposed tracking mechanism. If this cannot be confirmed, please explain.

e. Because the regulatory liability referenced in part (d) is considered to be a cash transaction, the $40 million regulatory liability would reduce rate base and be amortized over 5-years, commencing with the effective date of rates in the next rate case. If this cannot be confirmed, please explain.

f. Referring to part (e) above, the tracking mechanism envisions that the 5-year amortization would not "sunset" between rate cases but would be tracked until the next proceeding for prospective true-up. If this cannot be confirmed, please explain.

g. Referring to part (b) above, the Company would record a regulatory accrual offsetting the negative expense by debiting O&M expense for $10 million and creating a separate regulatory liability of $10 million. Because the negative expense is non-cash and the related prepaid asset is not included in rate base under the tracking mechanism, this second regulatory liability would also not be recognized as a rate base offset or amortized in future rate case proceedings. If this cannot be confirmed, please explain.

Response:

a. Yes.

b. Your statement is true under the current FAS 87 and FAS 106 accounting standards. However, under FAS 158, the funded status of the plan is recorded directly on the balance sheet. All deferred costs are recognized as other comprehensive income as a charge to equity. The sum of these two items equal the current concept of an (accrued)/prepaid pension liability or asset.

c. Yes, the negative pension expense and offsetting regulatory liability will not be recognized in rate base.

d. Yes.

e. Yes.

f. Yes, the prospective "true-up" is necessary to ensure rate payers neither over or under pay.

g. Yes.

Prepared By: C. Kenneth Vogi
Title: Principal
Date: December 13, 2006

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF MISSOURI

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

AFFIDAVIT OF STEVEN C. CARVER

STATE OF MISSOURI)
) ss
COUNTY OF JACKSON)

Steven C. Carver, 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.

Steven C. Carver

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

Notary

NOTARY PUBLIC NOTARY SEAL STATE OF MISSOURI

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