Exhibit No.:
Issues: Depreciation; Steam Production Plant Retirement Dates; Decommissioning Costs; Callaway Interim Additions
Witness: Rosella L. Schad
Sponsoring Party: MoPSC Staff
Type of Exhibit: Surrebuttal Testimony
Case No.: EC-2002-1
Date Testimony Prepared: June 24, 2002

MISSOURI PUBLIC SERVICE COMMISSION

UTILITY SERVICES DIVISION

SURREBUTTALTESTIMONY

OF

ROSELLA L. SCHAD

UNION ELECTRIC COMPANY d/b/a AMERENUE

CASE NO. EC-2002-1

Jefferson City, Missouri
June 2002

****'Denotes Proprietary Information****
****Denotes Highly Confidential Information****

NP

Exhibit No. 48 NP
Date 7/10/02 Case No. EC-2002-1
Reporter KRM

BEFORE THE PUBLIC SERVICE COMMISSION

OF THE STATE OF MISSOURI

The Staff of the Missouri Public Service Commission,	)	Case No. EC-2002-1
	)	
Complainant,	)	
vs.	)	
	)	
Union Electric Company, d/b/a AmerenUE,	)	
	)	
Respondent.		

AFFIDAVIT OF ROSELLA L. SCHAD

STATE OF MISSOURI)
) ss.
COUNTY OF COLE)

Rosella L. Schad, is, of lawful age, and on her oath states: that she has participated in the preparation of the following Surrebuttal Testimony in question and answer form, consisting of 23 pages to be presented in the above case; that the answers in the following Surrebuttal Testimony were given by her; that she has knowledge of the matters set forth in such answers; and that such matters are true and correct to the best of her knowledge and belief.

Rosella L. Schad
Rosella L. Schad

Subscribed and sworn to before me this 24th day of June, 2002.

Toni M Charlton

TONI M. CHARLTON NOTARY SEAL NOTARY PUBLIC STATE OF MISSOURI

TONI M. CHARLTON
NOTARY PUBLIC STATE OF MISSOURI
COUNTY OF COLE
My Commission Expires December 28, 2004

SURREBUTTAL TESTIMONY

OF

ROSELLA L. SCHAD

UNION ELECTRIC COMPANY

d/b/a AMERENUE

CASE NO. EC-2002-1

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SURREBUTTAL TESTIMONY

OF

ROSELLA L. SCHAD

UNION ELECTRIC COMPANY

d/b/a AMERENUE

CASE NO. EC-2002-1

Q. What is your name and business address?

A. Rosella L. Schad, P.O. Box 360, Jefferson City, MO 65102.

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

A. I am employed by the Missouri Public Service Commission (PSC or Commission) as an Engineer I in the Engineering and Management Services Department.

Q. What are your duties as an Engineer in the Engineering and Management Services Department?

A. I am responsible for engineering analyses and depreciation determinations of companies regulated by the Commission.

Q. What are your qualifications, educational background and experience?

A. In 1978, I earned a Bachelor of Science degree in Mechanical Engineering from the University of Missouri-Columbia. I am a registered Professional Engineer in Missouri. I was employed by Union Electric (now AmerenUE) as an engineer intern during the summer of 1977 and employed as a mechanical engineer by Union Electric in its Nuclear Construction Department from 1978-1980. I joined the Missouri Public Service Commission Staff in the Depreciation Department in 1999.

Q. Have you previously filed testimony before this Commission?

A. Yes. As shown in Schedule 1 attached to my testimony is a list in which I have previously filed testimony.

Q. Have you previously filed testimony in the July 2001 filing or the March 2002 filing in this case?

A. No.

Q. What is the purpose of your testimony in this case?

A. The purpose of my testimony in this case is to present Staff's surrebuttal position of Company witnesses Garry L. Randolph and Thomas LaGuardia. I will also present Staff's surrebuttal position of Company witness William Stout, P.E. as does Staff Witness Jolie Mathis.

Q. What issues will you address?

A. I will address:

1) The Company's use of depreciation rate determination to attain a targeted level of cash flow for future infrastructure needs;
2) The Company's retirement dates for fossil-fueled production plant accounts and the truncation of average service lives (ASL) for determining the appropriate depreciation rate;
3) The Company's projected decommissioning costs for fossil-fueled plants and the recovery of these future costs, which are speculative, by current ratepayers;
4) Determination of ASL for Callaway Nuclear Production Plant accounts; and

5) The Company's amortization to address a depreciation reserve deficiency, which in the absence of issues 2), 3), 4) and the issue of Distribution Plant cost of removal (addressed by Staff Witness Ms. Jolie Mathis) does not exist.

I. DEPRECIATION RATE DETERMINATION

Q. Why is depreciation rate determination an issue?

A. Depreciation rate determination is an issue because setting depreciation rates to attain a targeted level of cash flow for future capital investments is being proposed by AmerenUE (Company) and is opposed by the Staff.

Q. How does the Company benefit from formulating a relationship between depreciation expense and major capital improvements?

A. The Company benefits by receiving more dollars through depreciation expense.

Q. How can the Company achieve the desired results?

A. The Company can achieve the desired results in three ways: shortened plant average service lives (ASL), increased net salvage, and positive annual amortizations for reserve variances.

Q. For purposes of the Company's rebuttal testimony, which mechanism did they choose to propose?

A. All three. As a result of Mr. Stout's depreciation parameters, ASL and prospective cost of removal, Mr. Stout recommends that a $5 million annual amortization (Stout's rebuttal testimony, Schedule 1- Depreciation Study, page III-15) is necessary to correct a reserve deficiency. The Company has proposed that depreciation expense, including amortizations to the depreciation accrued reserve, need to be increased $30 million from current levels of depreciation expense. Mr. Stout and the Company propose to continue and increase prospective cost of removal.

Q. Does Mr. Stout acknowledge that in order to justify depreciation expense in excess of currently incurred amounts that AmerenUE should project large capital expenditures?

A. Yes. Projecting high capital expenditures might be one way to justify excess depreciation expense. ** P---
P--
P--- ---
P--.
P---------------------**

Q. How did recovery of prospective cost of removal, increase depreciation expense, and a need for major capital improvements become an impetus in the current case?

A. These three issues became an impetus in the current case because in Case No. WR-2001-844 St. Louis County Water, asked to recover prospective cost of removal through depreciation expense while stressing its need for major capital improvements. The Commission's Report And Order addressed this argument:

> ...There is ample factual support to allow the Commission to choose either Staff's approach or the Company's. Under the circumstances faced by the Company, including its need for cash flow to address its infrastructure issues, the Commission concludes that using the whole life method and including estimated net salvage is in the public interest. The whole life method collects net salvage cost ratably over the life of plant by customers served by the plant. This approach is equitable based on the circumstances of this case...

St. Louis County Water's currently ordered depreciation rates include prospective cost of removal.

Q. Does the Commission's Report And Order have additional clarification?

A. Yes. The Commission's Report And Order also states:

> ...The Commission explicitly distinguishes its holding on the net salvage issue here from its holding in Laclede Gas Company's recent case, Case No. GR-99-315. The Commission's holding that the Company's use of the whole life method of determining depreciation rates is based on the record in this case, and on the circumstances in which the Company finds itself. The whole life method is not appropriate for all types of property, for all utilities, and in all situations...

Q. Do you know of any authoritative text on depreciation that states that meeting the needs for cash flow to address infrastructure issues is a proper consideration in calculating depreciation rates?

A. No.

Q. On page 24, beginning with line 2 of his rebuttal testimony Mr. Stout states:

> AmerenUE is experiencing a tremendous demand for capital to increase its reserve margin, reinforce its transmission systems and meet the needs of its customers...Current depreciation expense approximates $270 million. A 10 percent increase to $300 million will reduce the amount of outside capital required. Staff's proposal to decrease depreciation to less than $200 million will substantially increase the amount of outside capital required and most likely would have a negative impact on the cost of capital...

Does Mr. Stout's statement consider depreciation expense a source of cash flow for addressing future infrastructure needs of the Company?

A. Yes.

Q. Does Mr. Stout include in his definition of depreciation, or as a proper consideration in calculating depreciation rates, that depreciation should attain a targeted level of cash flow for future infrastructure?

A. No. Mr. Stout does not take such a step in his description of his depreciation analysis, as given on page 8, lines 3 to 5 of his rebuttal testimony.

Q. Does Staff target a level of cash flow for future infrastructure needs as part of their depreciation analyses of regulated companies?

A. No. It continues to be Staff's position that depreciation should not be set at a level to achieve a given level of cash flow for future infrastructure needs.

Q. In Mr. Stout's current depreciation study, are there specific changes in methodology for estimating net salvage percentage, which result in the Company's recovering increased depreciation expenses from current levels?

A. Yes. The Company, in its depreciation estimates, has included estimated future decommissioning costs for fossil-fueled plants.

Q. Are there other areas of prospective net salvage costs?

A. Yes. Cost of removal of Distribution Plant represents a significant net salvage cost and is addressed by Staff Witness Ms. Jolie Mathis.

Q. In summary, is it Staff's position that targeting a level of cash flow for future infrastructure needs, as part of a depreciation analysis, is inappropriate?

A. Yes.

II. THE COMPANY'S RETIREMENT DATES FOR PRODUCTION PLANT

Q. Why are the Company's retirement dates for production plant an issue?

A. These retirement dates for production plant are an issue because AmerenUE is projecting the date certain that generation plant will be retired and then using these dates as the basis for shortening average service lives (ASLs) and increasing the depreciation rates for its generation plant. As I state earlier, shortening ASLs' is one of the three ways to increase depreciation expense to achieve increased revenue requirements.

Q. Does Mr. Stout acknowledge that average service lives increase if truncation of the survivor curves occurs 15 years later than the Company's proposed retirement dates?

A. Yes. In work papers provided in the response to Staff's Data Request No. 4721 (Schedule 3), Mr. Stout acknowledges that, "The average lives for most installation years would increase if the interim survivor curves were truncated 15 years later than the age at which they truncated in the calculations presented in Schedule 1." (Stout's Depreciation Study) The effect of using dates certain for retiring generating units has the impact of shortening plant service lives. The truncation of the ASL curve results in increased depreciation rates.

Q. Has the Commission recently addressed proposed truncation of the ASL curve for lifespan plant for other electric utilities in Missouri?

A. Yes. Truncation of ASLs for lifespan production plant was addressed in The Empire District Electric Company's Case No. ER-2001-299.

Q. Are truncated ASLs for lifespan production plant currently ordered for The Empire District Electric Company?

A. No. The Commission's Report And Order in that case ordered the Company to adopt ASLs estimated from non-truncated ASL curves for lifespan production plant.

Q. Do you agree with Mr. Stout's assertion, on page 33 of his rebuttal testimony, that Staff witness' inability to estimate the final retirement dates with certainty is not a valid reason for not truncating the survivor curves?

A. No. A determination of the exact timing of the retirement of a particular facility can only be made relatively close to the time of its anticipated retirement date. Until that time, many variables such as power supply replacement, technology improvements, market conditions, and regulatory requirements change over time. Because retirement is a function of many variables that change over time, the final retirement date is uncertain and it is inappropriate to truncate the survivor curve at this time. These units will continue to remain in operation as long as it is economical and feasible to do so.

Q. Does the Company acknowledge that the useful life of any generating facility is determined by the interaction of a host of variables and that these variables are ever changing over time?

A. Yes. Company Witness Garry Randolph states on page 18, lines 3-4 of his rebuttal testimony, "Moreover, the variables, which include such things as technology improvements and regulatory requirements, are ever changing over time." In addition, Mr. Randolph states on page 19, line 17-19, "In the end, consideration of the unique circumstances of each facility as the estimated retirement date approaches will be the final determinant for a retirement."

Q. Did you find support for Mr. Stout's use of the proposed retirement dates for production plants?

A. No. Mr. Stout, on page 34 of his rebuttal testimony states, "Thus a probable, although not certain, retirement date can be estimated and used in the determination of annual and accrued depreciation for power plants." Mr. Stout supports his use of the proposed retirement dates by reference to the reasonableness of retirement dates provided by Company Witness Garry Randolph and AmerenUE's management, and by comparisons of his composite average lives to the mean lives of retired plant from other electric utilities. However, in work papers provided in the response to Staff's Data Request No. 4723 (Schedule 4), the Company acknowledges that, "...Engineering judgement rather than a specific analysis was used to determine the retirement dates..." Notably absent is a specific engineering or economic analysis by the Company to determine the retirement dates.

In fact, the scope of the Company's evaluations was superficial as evident by the fact that no documentation (workpapers required to be produced to the parties) was produced as a result of AmerenUE's review of the probable retirement dates for their generating units.

Q. Does Staff have other questions with the retirement dates given by Mr. Randolph?

A. Yes. In Schedule 5 attached to Mr. Randolph's rebuttal testimony he provides the retirement dates for nine production plants. ** HC-- HC-- HC-- HC-- HC--- ** Staff questions the reasonableness of these final estimated retirement dates and the effects on the reliability of AmerenUE's system.

Q. In the absence of a specific engineering analysis has the Company provided the necessary support for their final estimated retirement dates and the truncation of the ASL curve for lifespan production plant, thereby increasing their depreciation rates?

A. No. On page 39 of his rebuttal testimony, Mr. Stout has shown how a component of his Steam Production Plant's depreciation rates are derived. "I estimated the life characteristics of Steam, Nuclear and Hydraulic Production Plant using truncated survivor curves." The truncation of ASLs proposed by Mr. Stout substantially increases depreciation rates and the annual depreciation accrual without the supporting benefit of a reasoned analysis.

Q. Should the Commission reject the Company's ASL's and depreciation rates for Steam Production accounts?

A. Yes.

Q. What is the increase in annual depreciation accrual, based on September 30, 2001 plant balances, due to Company's truncation of the ASL curve for AmerenUE's Steam Production Plants?

A. The increase in annual depreciation accrual, based on September 30, 2001 plant balances, due to Company's truncation of the steam production plant's ASL curve is $28 million.

<u>III. DECOMMISSIONING COSTS FOR FOSSIL-FUELED PLANTS</u>

Q. Why are decommissioning costs for the fossil-fueled plants an issue?

A. Decommissioning costs for the fossil-fueled plants are an issue because it is speculative as to both the time dismantling will occur and the dollar amount that will be incurred. Given this uncertainty it is questionable as to whether current customers should pay the expense of removal.

Q. Do you agree with Mr. Stout's position on net salvage estimates?

A. No. On page 20, lines 13-15 of his rebuttal testimony, he states, "Since there is somewhat greater certainty in the net salvage estimate given the conservative nature of the estimates, I conclude that it also is reasonable to use estimates of net salvage for depreciation purposes." However, Mr. Stout built into depreciation rates an estimate that is premised on the most expensive retirement option. Mr. Stout has ignored the fact that the Company should choose its most economical one. The Company will make this decision at the time it is required to make a decision on unit retirement and dismantlement.

Q. How does Mr. Stout arrive at the net salvage estimates he uses for fossil-fueled plants?

A. On page II-27 of his Depreciation Study he states:

> ...The decommissioning cost estimates for each location were based on the results of decommissioning studies conducted by TLG Services, Inc. a consulting engineering firm. The Decommissioning cost estimates were stated in current (2001) dollars. The decommissioning of the steam production plants are projected to occur at various dates in the future. The decommissioning cost estimates were adjusted for the effect of inflation between 2001 and the projected retirement date to develop the net salvage percent estimate as shown in the table on the following page.

Q. Does TLG Services, Inc. take into consideration economic alternatives the Company may have regarding dismantlement?

A. No. On page 10, lines 7-11 of his rebuttal testimony Company Witness Thomas S. LaGuardia states, "...Dismantling and demolition of the Labadie, Rush Island, Sioux, Meramec and Venice fossil-fired steam electric generating stations was estimated to cost approximately $337.6 million total (2001 dollars), including credit for the scrap generated in the dismantling process. Each site was assumed to be dismantled upon the cessation of the final unit's operation." Other economic alternatives the Company may have available regarding dismantlement are never considered or analyzed

Q. What other alternatives might be considered?

A. Reuse of the site, facilities for new generating plant, or sale of the site as-is (Schedule 5).

Q. Mr. LaGuardia identifies other fossil-fueled plants used as cost-estimate models in his decommissioning study? Can you provide a list of those plants?

A. Yes. ** HC-- HC-- HC-- HC-- -- HC-----**

Q. ** HC-- HC-- HC--**

A. ** HC-- HC-- HC--**

Q. Did Mr. LaGuardia perform original detailed site-specific dismantling costs for each of AmerenUE's four fossil-fueled plants?

A. No. According to his rebuttal testimony, page 10, lnes 6-8, Mr. Laguardia states, "The dismantling costs were compared to other fossil-fueled plants with detailed dismantling cost estimates prepared by TLG."

Q. Do the detailed dismantling cost estimates of other fossil-fueled plants that were used in the study approximate the actual costs incurred to dismantle those fossil-fueled plants?

A. No. None of the fossil-fueled plants used as cost-estimate models in Mr. LaGuardia's AmerenUE study have been dismantled, there is no way to determine if the cost estimates provided to AmerenUE approximate the actual costs AmerenUE could reasonably anticipate to incur in the future.

Q. Does Mr. LaGuardia list any Missouri fossil-fueled plants, which have been dismantled?

A. Yes. On page 27, line 1-5 of his rebuttal testimony, he refers to Kansas City Power & Light's retired and dismantled Northeast Station Plant located in Kansas City.

Q. Is Staff aware if dismantlement costs and site remediation costs were incurred after retirement of this 133 MW plant in 1982 (Schedule 8)?

A. Yes.

Q. Did Staff consider and treat these costs to be the final removal costs of life span type property?

A. Yes.

Q. Did the Commission adopt Mr. LaGuardia's studies and a similar analysis in the establishment of Kansas City Power & Light's depreciation rates?

A. No.

Q. Is Staff aware of other fossil-fueled units in Missouri, which were retired but not dismantled?

A. Yes. Kansas City Power & Light has units at its Hawthorn Plant site, which are retired (Mr. Stout's rebuttal testimony, Schedule 11-1) but have never been dismantled.

Q. Has Mr. Stout, Mr. LaGuardia, or any other Company witness addressed in their rebuttal testimonies alternatives to the decommissioning cost estimates used by Mr. Stout in his depreciation study?

A. No.

Q. Does Mr. LaGuardia's decommissioning study or his rebuttal testimony provide sufficient evidence to support that his estimates, which have not been verified for accuracy, will develop the correct level of recovery for the Company's fossil-fueled plants?

A. No. Mr. LaGuardia's decommissioning study lacks a verifiable database of decommissioned power plants similar in size and type for which dismantling costs have been confirmed. In addition, as previously stated, the plants Mr. LaGuardia utilizes for his decommissioning study have not actually been dismantled. Staff has not yet received related Data Request responses, which could affect this answer.

Q. Does Mr. LaGuardia's listing of the English Station at 135 MW capacity (Schedule 9), the cost model power plant used for comparison with Venice, correlate with the capacity reported by United Illuminating Company's reporting of the power plant in its 2000 Annual Report (Schedule 10)?

A. United Illuminating Company's annual report lists the capacity of English Station as 75 MW.

Q. What other concern does Staff have with the decommissioning cost estimates provided by Mr. LaGuardia?

A. Staff's concern with Mr. LaGuardia's decommissioning cost estimates is that there is no discussion or study that dismantling represents the most prudent alternative the Company has regarding their fossil-fueled plants final retirement.

Q. What other concerns does Staff have with the net salvage estimates built into Mr. Stout's depreciation rates?

A. Staff questions the future net salvage estimates built into Mr. Stout's depreciation rates, shown on page II-28 of his depreciation study as –26.1% for Meramec, -

24.4% for Sioux, -52.2% for Venice, -25.8% for Labadie, and –28.5 % for Rush Island. It should be noted that negative net salvage percentage estimates are indicators of prospective cost of removal. These net salvage percentage estimates will generate an ever-increasing depreciation expense as plant balances grow, not a defined level as the original net salvage estimates provided to Mr. Stout by TLG.

Because Mr. Stout's annual depreciation accrual is a function of plant balances, the effect of incorporating future net salvage estimates, as percentages, into the depreciation rates means that as plant balances increase so will the annual accruals for future net salvage amounts. Thus instead of accumulating annual amounts, which will equal the amounts of net salvage estimated by Mr. LaGuardia, as plant balances grow the net salvage amounts will grow by the same percentage. Staff's position is that the level of recovery from current customers proposed by the Company for future decommissioning costs for steam production plant is not justifiable. Mr. Stout's inclusion of these decommissioning costs in his depreciation rates will result in AmerenUE's customers being forced to pay even more than Mr. LaGuardia recommends.

Q. What is the benefit to the Company of large prospective negative net salvages percentages in the depreciation rates?

A. The benefit to the Company is that they have more cash to spend in any manner they wish. Large prospective negative net salvage percentages in the depreciation rates results in the Company collecting more money each year from customers in its utility rates.

Q. Mr. LaGuardia bases his estimates on the assumption that each site will be dismantled promptly upon the cessation of the final unit's operation. He also allows that site remediation is included in the estimate. What is his rationale for proposing the appropriate alternative is immediate dismantling of a power plant after it is retired?

A. His rationale for prompt dismantling, as given on page 24, lines 15-20 of his rebuttal testimony, is:

> Securing, maintaining and guarding retired power plants indefinitely is costly, which will require either a full-time guard force, and/or intrusion detection devices and alarms monitored by local law enforcement agencies, as well as general building maintenance to keep the structures in a safe condition. Furthermore, prompt dismantling of retired power plants makes the site available for alternative uses at the earliest possible time.

Q. In discussions with the Company and Staff on February 8, 2002 and in which you participated, did the Company employees indicate that there were no plans to dismantle Venice?

A. Yes.

Q. Is there any guarantee that the dollars a regulated electric utility has collected in the depreciation reserve for future net salvage costs will be available years from now if and when the Company's steam production plants retire?

A. No. AmerenUE is only proposing that future net salvage costs be collected from its customers. The only funds that are guaranteed to exist when plant retires is the decommissioning fund for nuclear generation facilities, which is not an issue in this case. The cost of removal dollars a regulated utility has collected in the depreciation reserve for steam production plant cannot be guaranteed to exist even in five years from now, much less many years into the future. The dollar amounts are commingled in the depreciation reserve resulting in an inability to even identify how much cost of removal has been collected from customers.

Q. What is the increase in annual depreciation accrual, based on September 30, 2001 plant balances, due to Company's determination of future decommissioning costs for steam production plant in depreciation rates?

A. The increase in annual depreciation accrual, based on September 30, 2001 plant balances, due to Company's determination of future decommissioning costs for steam production plant included in depreciation rates is $16 million.

IV. DETERMINATION OF ASL FOR THE CALLAWAY NUCLEAR PLANT

Q. Why is the determination of ASL for the Callaway Nuclear Plant accounts an issue?

A. Determination of ASL for the Callaway Nuclear Production Plant accounts is an issue because the ASL will, through depreciation rates, establish the level of annual depreciation expense current customers must pay in utility bills.

Q. Can you provide information regarding current trends in the nuclear industry, which would have a significant impact on the evaluation of the reasonableness of an appropriate depreciation rate for Callaway?

A. Yes. The Nuclear Regulatory Commission NRC has issued renewed licenses for six nuclear power plants in the U.S., including Arkansas Nuclear One, Unit 1 on May 30, 2002 (Schedule 11). Several other nuclear power plants have made license renewal applications (Schedule 12). In another neighboring state, the Kansas Corporation Commission (KCC) has reduced the annual depreciation rate for Western Resources for Wolf Creek Nuclear Production Plant accounts to 1.73% (Schedule 13). Wolf Creek is a nuclear unit that is designed similar to Callaway. This reduction is based on the KCC's assumption that the Wolf Creek Nuclear Plant will request and obtain a 20-year license extension from the (NRC).

Q. May the Company apply, in the future, for an extension of the Callaway Nuclear Plant's operating license?

A. Yes. The Company may make an application for license renewal to the NRC in 2004.

Q. Has the Company made any commitment to Staff that they will not be applying for an extension of the license, such that the plant is guaranteed not to operate past 40 years?

A. No.

Q. Then do you agree with Mr. Stout when he acknowledges, on page 43 of his rebuttal testimony, that it is conceivable that the license could be renewed?

A. Yes.

Q. If Callaway's operating license is renewed for an additional 20-year period, would customers paying for its service in the first 20 years have paid too much for recovery of capital original plant costs?

A. Yes. Applying a 40-year ASL will generate an inappropriate level of annual depreciation and accrued depreciation if Callaway's operating license is extended.

Q. Do Staff depreciation rates for Callaway include recovery for future interim additions?

A. No. Staff does not include recovery for future interim additions because these costs cannot be specified and measured at the present time, either as to the time they will occur or the dollar amount that will be incurred.

Q. Did Staff propose a 2.5% depreciation rate based on a 40-year ASL for the Callaway accounts?

A. Yes. Staff used a 2.5% depreciation rate based on a 40-year ASL for Callaway's accounts which assures the life parameter in the depreciation rate will sufficiently recover the original capital plant cost for customers during its licensed 40-year operating life without undue upfront weighting, given the probability that the licensed operating life will be extended by 20 years.

Q. Does Mr. Stout point out the potential for an under-accrual of Callaway's accrued reserve?

A. Yes. On page 35, lines 21-23 of his rebuttal testimony, he states that Staff's 40-year ASL will result in an overstatement of the average lives of the Nuclear Production Plant accounts and an understatement of the annual and accrued depreciation.

Q. Is it more probable that Callaway's depreciation reserve will be over- or under-accrued?

A. It is more likely that Callaway's depreciation reserve will be over-accrued, given the likelihood that Callaway's life will be extended.

Q. How would Staff recommend handling any under-accrual of the accrued depreciation reserve that could potentially exist at the conclusion of the 40-year operating license if a license extension is not obtained for Callaway Nuclear Plant?

A. Staff's recommendation, for lifespan type plant that has an under-accrual of its depreciation reserve at the end of its life span, is an amortization to the accrued reserve. This will assure full recovery to the Company of all original capital plant costs. This matter will be monitored in each future depreciation review.

Q. How much does the use of the Company's ASLs in depreciation rates for Callaway Nuclear Production Plant accounts, based on September 30, 2001 plant balances, add to the annual accrual?

A. The use of the Company's ASLs in depreciation rates for Callaway Nuclear Production Plant accounts, based on September 30, 2001 plant balances, adds $8 million to the annual accrual.

Q. Does Staff's proposed depreciation rate of 2.5% and ASL of 40-years for all of Callaway's accounts incorporate interim retirements as the currently ordered rates do?

A. No. Currently, Callaway's ordered depreciation rates have an additional 0.1% adder (2.5% + 0.1% =2.6%) for interim retirements. In the absence of consideration of any additional trends in the nuclear industry, the Commission may find that the currently ordered depreciation rate of 2.6% is appropriate to re-adopt for Callaway's accounts.

V. THE COMPANY'S RECOMMENDED ANNUAL AMORTIZATION

Q. Why is the Company's recommendation for a 20-year annual amortization an issue?

A. The Company's recommendation for a 20-year annual amortization of $6 million is an issue because the reserve deficiency, as defined by Mr. Stout, is totally dependent on Commission's finding that the Company's issues (e.g. future decommissioning costs) discussed in my testimony and another significant issue, discussed in Ms. Mathis' surrebuttal testimony (i.e., cost of removal of Distribution Plant) are reasonable. If the Commission does not accept these positions, then AmerenUE will have a depreciation reserve surplus.

Q. In reviewing Company's filing, did Staff find that Mr. Stout's annual amortization for reserve deficiency of $4,825,225 is the proposed booked amount by the Company in this case?

A. No. Staff is still investigating this amount. At the time of this filing, Staff has submitted a Data Request to the Company to determine why their proposed annual amortization for reserve deficiency of $5,917,744 is $1,092,519 higher (Schedule 14) than Mr. Stout's reserve variance of $4,825,225, as given in Table B on page III-15 of his Depreciation Study.

Q. Does Staff's Depreciation Engineers agree with Mr. Stout that the currently ordered depreciation rates are not appropriate to determine current revenue requirements?

A. Yes. The current depreciation rates, excluding Callaway, were established in 1983. Callaway's depreciation rates were established in 1984. The Commission should establish new rates.

Q. On page 51, lines 7-9, of his rebuttal testimony, Mr. Stout recommends a 20-year annual amortization, as supported on page 51 of his rebuttal testimony, "I further recommend the initiation of an amortization of the variance between the calculated accrued depreciation and the book accumulated depreciation as shown in column 4 of Table C." Do you agree with Mr. Stout's recommendation for the 20-year annual amortization?

A. No. Staff does not find that the Company's testimony, noted in 1) – 4) above and on the other significant issue, Distribution Plant cost of removal, have merit. Consequently, Staff does not find the Company's theoretical reserve to be valid.

Q. Does Staff find the Company's arguments, for these five significant issues in this case, to be reasonable?

A. No. The Company's arguments for Distribution Plant cost of removal ($35 million), steam production plant retirement dates/truncated ASLs ($28 million), decommissioning of steam production plant-cost of removal ($16 million), Callaway's ASL ($8 million), and amortization for reserve deficiency ($6 million) are not supported by adequate data and analysis.

Q. Is it Staff's position that a reserve deficiency does not exist?

A. Yes.

Q. Based on your review and in the absence of credible support for the Company's position on production plant retirement dates, dismantling costs for steam production plant, and depreciation rates for Callaway's accounts, should the Commission reject the Company's 20-year amortization for its proposed deficiency in the depreciation accrued reserve?

A. Yes.

Q. In fact, is it Staff's position that the Commission should not retain the currently ordered depreciation rates for the Company's Production and Distribution Plant accounts?

A. Yes. Current depreciation rates for the Company's Production and Distribution Plant accounts are based on understated Production Plant lives and large unpaid cost of removal amounts for Distribution Plant. These facts have generated an annual depreciation expense that is excessive.

Q. In summary, what is Staff's proposal?

A. Staff's proposal is:

That the Commission should order Staff's proposed depreciation rates and plant ASLs for AmerenUE's plant accounts, effective on the date of this Order.

Q. Does this conclude your testimony?

A. Yes, it does.

CASE PROCEEDING PARTICIPATION

ROSELLA L. SCHAD

COMPANY	CASE NO.
Iamo Telephone Company	TT-2001-116
Peace Valley Telephone Company	TT-2001-118
Holway Telephone Company	TT-2001-119
KLM Telephone Company	TT-2001-120
Ozark Telephone Company	TC-2001-402
Osage Water Company	SR-2000-556
Osage Water Company	WR-2000-557
Northeast Missouri Rural Telephone Company	TR-2001-344
Oregon Farmers Mutual Telephone Company	TT-2001-328
Laclede Gas Company	GR-2001-629
Laclede Gas Company	GR-2002-356

SCHAD

SCHEDULE 2

IS DEEMED

PROPRIETARY

IN ITS ENTIRETY

AmerenUE's Response to
MPSC Staff Data Request
Case No. EC-2002-1
Excess Earnings Complaint
Staff of the MPSC v. Union Electric Company d/b/a AmerenUE

No. 4721

(1) For production steam plant, how would the lives be affected if the Iowa curves were truncated 15 years later?

(2) Please provide the list of ten electric utilities you have conducted depreciation studies for over the past 10 years.

(3) What is the date of the AGA/EEI Study listed in Schedule 12? What is the size, fuel type, boiler type, rating in-service data, and efficiency of each plant of each utility? What are the dates of the depreciation studies reported in the study? (Some have the year 1998, and some say 1/29).

Response:

(1) The average lives for most installation years would increase if the interim survivor curves were truncated at an age 15 years later than the age at which they are truncated in the calculations presented in Schedule 1.

(2) The ten electric utilities for which I have conducted depreciation studies during the past ten years are:

Arizona Public Service Company
Chugach Electric Association, Inc.
Cincinnati Gas and Electric Company
Duquesne Light Company
Newfoundland Light & Power Co. Limited
Northwest Territories Power Corporation
Omaha Public Power District
Reliant Energy
UGI Utilities, Inc. – Electric Division
West Penn Power Company

(3) The AGA/EEI survey provided in Schedule 12 and in the response to No. 4720 is labeled 1998-1999 and was distributed in October 1999. The requested plant data are not available. The dates of the studies vary and generally represent the most recent study conducted or the most recent date that parameters and rates were approved by a regulatory body.

Signed by: William M. Stout
Prepared By: William M. Stout, P.E.
Title: President, Valuation and Rate Division
Gannett Fleming, Inc.

NO. ____

DATA INFORMATION REQUEST
UNION ELECTRIC COMPANY dba AMERENUE
CASE NUMBER EC-2002-1

Requested From: Garry Randolph/Mary Hoyt

Date Requested: June 4, 2002

Information Requested:

At page 18 of Mr. Randolph's rebuttal testimony he states: "AmerenUE Generation has conducted a review of all of the AmerenUE generating facilities' retirement dates. This review considered experiences, observations, investment plans and unique circumstances associated with the specific generating facilities being considered, coupled with the uncertainty of future regulatory changes, technology advancements and market reliability. This review has resulted in the estimated retirement dates shown in my attached Schedule 5."

1.) Mr. Randolph has not provided documentation of the above "review" as work papers with his rebuttal testimony. Also such documentation was not provided when AmerenUE submitted its depreciation study and work papers. The Staff requests a timely response to the following questions noting that AmerenUE agreed in its joint filing with the Staff on December 26, 2001 that it would use its best efforts to respond to Staff's data requests as quickly as possible. Please provide responses to the questions that follow as the responses become available.

1. For each generation plant listed on Schedule 5, please provide information, work papers, memoranda, summary of internal discussion or any other materials or studies relevant to "experiences" as this relates to the plant's estimated retirement date.

2. For each generation plant listed on Schedule 5, please provide information, work papers, memoranda, summary of internal discussion or any other materials or studies relevant to "observations" as this relates to the plant's estimated retirement date.

3. For each generation plant listed on Schedule 5, please provide information, work papers, memoranda, summary of internal discussion or any other materials or studies relevant to "investment plans" as this relates to the plant's estimated retirement date.

4. For each generation plant listed on Schedule 5, please provide information, work papers, memoranda, summary of internal discussion or any other materials or studies relevant to "unique circumstances" as this relates to the plant's estimated retirement date.

5. For each generation plant listed on Schedule 5, please provide information, work papers, memoranda, summary of internal discussion or any other materials or studies relevant to "uncertainty of future regulatory changes" as this relates to the plant's estimated retirement date.

6. For each generation plant listed on Schedule 5, please provide information, work papers, memoranda, summary of internal discussion or any other materials or studies relevant to "technology advancements" as this relates to the plant's estimated retirement date.

7. For each generation plant listed on Schedule 5, please provide information, work papers, memoranda, summary of internal discussion or any other materials or studies relevant to

For the materials provided in items 1-7, please also provide a "road map" indicating how these materials were taken into account in estimating the retirement dates.

2.)

1. Please describe the review process that was "conducted" by AmerenUE Generation. Specifically include:

   a. Scheduled meetings involved in the review, including meeting dates and agendas.
      i. AmerenUE Generation employees involved in the review process and in attendance at each meeting.
      ii. Ameren Services employees involved in the review process and in attendance at each meeting.

   b. A description of the methodology by which the review process was designed to operate and arrive at an estimate of retirement dates.
      i. A description of specific information or studies that were designed to be included as part of the review process.
      ii. A description of how it was intended for the review process to be documents in work papers.

   c. A description of the teams involved in the decision making process.
      i. What was the makeup of the management team responsible for approving the decision on estimated retirement dates?
      ii. Who, if any one individual, had the final approval of the estimated retirement dates?

2. If specific information, work papers, or other studies related to the plants' estimated retirement dates were not developed, would it then be true that "engineering judgment" rather than a specific analysis was used to determine these retirement dates? If not, why not?

3. Did any employee or team member express concern with the final estimated retirement dates from the review? If yes, who expressed concern and what was their concern?

The review of retirement dates did not result in the development of specific information, work papers or other studies related to the plant's specific retirement dates. "Engineering judgement" rather than a specific analysis was used to determine the retirement dates. No employee expressed concern with the final estimated retirement dates.

Requested By: Rosella Schad, Engineer

Information Provided:

The attached information provided to the Missouri Public Service Commission Staff in response to the above data information request is accurate and complete, and contains no material misrepresentations or omissions, based upon present facts of which the undersigned has knowledge, information or belief. The undersigned agrees to immediately inform the Missouri Public Service Commission Staff if, during the pendency of Case No. EC-2002-1 before the Commission, any matters are discovered which would materially affect the accuracy or completeness of the attached information.

If these data are voluminous, please (1) identify the relevant documents and their location (2) make arrangements with requestor to have documents available for inspection in Union Electric Company's, St. Louis, Missouri office, or other location mutually agreeable. Where identification of a document is requested, briefly describe the document (e.g. book, letter, memorandum, report) and state the following information as applicable for the particular document: name, title, number, author, date of publication and publisher, addresses, date written, and the name and address of the person(s) having possession of the document. As used in this data request the term "document(s)" includes publication of any format, workpapers, letters, memoranda, notes, reports, analyses, computer analyses, test results, studies or data, recordings, transcriptions and printed, typed or written materials of every kind in your possession, custody or control or within your knowledge. The pronoun "you" or "your" refers to Union Electric Company and its employees, contractors, agents or others employed by or acting in its behalf.

Signed by: ______________________

Date Response Received: ______________________

Prepared by: __Michael Yuskus______________

SCHAD

SCHEDULE 5

IS DEEMED

HIGHLY CONFIDENTIAL

IN ITS ENTIRETY

No. 4724

DATA INFORMATION REQUEST
UNION ELECTRIC COMPANY dba AMERENUE
CASE NUMBER EC-2002-1

Requested From: Garry Randolph/Mary Hoyt

Date Requested: June 4, 2002

Information Requested:

1. Please provide copies of all bids for any contracts to dismantle the Venice generating plant.
2. Please provide a listing of local permits required to complete the demolition and required remediation.
3. Please provide copies of local permits already obtained for removal and site restoration.
4. Please provide a report of all monies spent toward a commitment to dismantle Venice.
5. Please provide a list of all regulatory agencies that must provide any type of approval or which require notification.
6. Please provide a list of state and federal regulations, which are required to initiate, process, or complete the demolition and required remediation of Venice.
7. Please provide a time line for all aspects of the Company's plan for dismantling and performing the required remediation.
8. Please provide the name of the department that is currently working or assisting on any of these details regarding Venice

Requested By: Rosella Schad, Engineer

Information Provided: Due to the decision reached in April, 2002 to retire Venice Plant in late 2003, we have not had the opportunity to complete long term plans for the utilization of the Venice site.

Part of those plans would need to address the amount of site restoration and demolition required for site usage. Regardless of the end-usage of the site, actions will have to be taken to provide system lay-up, physical barriers, and minor maintenance to maintain the facility in a safe condition until demolition and site restoration are pursued. It would be inappropriate to assume that the Venice site would never have to be demolished and restored in some fashion. But at this time, the exact cost, permits, timelines and plans are not completed.

When we have more information, this work would be performed by contractors arranged through the Generation Engineering and Technical Services group in AmerenUE. Based on the company's present timeline and plans stated herein, the above questions are not relevant.

The attached information provided to the Missouri Public Service Commission Staff in response to the above data information request is accurate and complete, and contains no material misrepresentations or omissions, based upon present facts of which the undersigned has knowledge, information or belief. The undersigned agrees to materially affect the accuracy or completeness of the attached information.

If these data are voluminous, please (1) identify the relevant documents and their location (2) make arrangements with requestor to have documents available for inspection in Union Electric Company's St. Louis, Missouri office, or other location mutually agreeable. Where identification of a document is requested, briefly describe the document (e.g. book, letter, memorandum, report) and state the following information as applicable for the particular document: name, title, number, author, date of publication and publisher, addresses, date written, and the name and address of the person(s) having possession of the document. As used in this data request the term "document(s)" includes publication of any format, workpapers, letters, memoranda, notes, reports, analyses, computer analyses, test results, studies or data, recordings, transcriptions and printed, typed or written materials of every kind in your possession, custody or control or within your knowledge. The pronoun "you" or "your" refers to Union Electric Company and its employees, contractors, agents or others employed by or acting in its behalf.

Signed by: ______________________

Date Response Received: ______________________

Prepared by: Michael Yuskus______________________

SCHAD

SCHEDULE 7

IS DEEMED

PROPRIETARY

IN ITS ENTIRETY

STEAM-ELECTRIC GENERATING PLANT STATISTICS (Large Plants) (Continued)

Additional and Other Expenses classified as "Other Power Supply Expenses."
9. For I.C. and G.T. plants report Operating Expenses, Acct. Nos. 548 and 549 on line 20 "Electric Expenses," and Maintenance Acct. Nos. 553 and 554 on line 32 "Maintenance of Electric Plant." Indicate plants designed for peak load service. Designate automatically operated plants.
10. If any plant is equipped with combinations of fossil fuel steam, nuclear steam, hydro, internal combustion or gas turbine equipment, each should be reported as a separate plant. However, if a gas turbine unit functions in a combined cycle operation with a conventional steam unit, the gas turbine should be included with the steam plant.
11. If the respondent operates a nuclear power generating plant, append: (a) a brief explanatory statement concerning accounting for the cost of power generated including any attribution of expenses to research and development expenses; (b) a brief explanation of the types of cost units used with respect to the various components of fuel cost, and (c) such additional information as may be informative concerning the type of plant, kind of fuel used, fuel enrichment by type and quantity for the reporting period and other physical and operating characteristics of the plant.
12. Schedule applies to Plant in Service only.

Plant Name (d)	Plant Name (e)	Plant Name (f)	Line No.
GRAND AVENUE STEAM	NORTHEAST GAS TURBINE	NORTHEAST STEAM	1
CONVENTIONAL	FULL OUTDOOR	CONVENTIONAL	2
1929	1972	1920	3
1949	1977	1940	4
126,750	485,000	133,000	5
72,100	317,000	-	6
3,888	1,116	-	7
			8
70,000	398,000	80,000	9
(1)		(1)	10
143	2	3	11
44,176,000	36,308,600	-	12
			13
$ 626,252	$ -	$ 362,202	14
3,821,027	-	5,418,435	15
16,511,993	40,809,440	12,518,131	16
$ 20,959,272	$ 40,809,440	$ 18,298,768	17
165	125	138	18
			19
$ 103,738	$ 481	$ 20,726	20
4,618,678	1,782,389	49,553	21
-	-	-	22
913,378	-	80,982	23
-	-	-	24
(3,356,088)	-	-	25
464,787	32,089	31,509	26
818,073	-	178,497	27
16,073	-	16,702	28
55,900	16,331	22,188	29
221,301	-	77,301	30
973,541	-	96,586	31
371,072	294,069	11,411	32
141,354	-	29,452	33
$ 5,341,762	$ 2,125,551	$ 614,910	34
120.92	59.00	-	35

(d) COAL	(d) OIL	(d) GAS	(e) OIL	(f) OIL	(f) GAS	Line No.
COAL	OIL	GAS	OIL	OIL	GAS	36
TON	BBL	MCF	BBL	BBL	MCF	37
78,479	1,446	985,705	94,076	431	21,478	38
12,672	137,605	950	137,632	137,443	950	39
30.661	37.092	2.159	34.518	34.318	1.215	40
31.383	19.101	2.159	18.946	54.409	1.215	41
1.238	3.305	2.273	3.278	9.425	1.279	42
	46.220		49.090	-		43
	29,360		17,978	-		44

Rev. Ed. (12-75)

Schedule 8-1

STEAM-ELECTRIC GENERATING PLANT STATISTICS (Large Plants)

1. Large plants for the purpose of this schedule are steam plants of 25,000 kw or more of installed capacity (name plate rating). Include gas-turbine and internal combustion plants of 10,000 kw and more in this schedule. Include nuclear plants.
2. If any plant is leased or operated as a joint facility, indicate such facts by the use of asterisks and footnotes.
3. If net peak demand for 60 minutes is not available, give that which is available, specifying period.
4. If a group of employees attends more than one generating plant, report on line 11 the approximate average number of employees assignable to each plant.
5. If gas is used and purchased on a therm basis, the B.t.u. content of the gas should be given and the quantity of fuel burned converted to M cu. ft.
6. Quantities of fuel burned (line 38) and average cost per unit of fuel burned (line 41) should be consistent with charges to expense accounts 501 and 547 (line 42) as shown on line 21.
7. If more than one fuel is burned in a plant furnish only the composite heat rate for all fuels burned.
8. The items under cost of plant represent accounts or combinations of accounts prescribed by the Uniform System of Accounts. Production expenses do not include Purchased Power, System Control and Load Dispatching

Line No.	Item (a)	Plant Name (b)		Plant Name (c)		
1	Kind of plant (steam, internal combustion, gas turbine or nuclear)	MONTROSE STEAM		HAWTHORN STEAM		
2	Type of plant construction (conventional outdoor boiler, full outdoor, etc.)	FULL OUTDOOR		OUTDOOR BOILERS (2)		
3	Year originally constructed	1958		1951		
4	Year last unit was installed	1964		1969		
5	Total installed capacity (maximum generator name plate ratings in kw.)	563,100		908,088		
6	Net peak demand on plant—kw (60 minutes)	520,000		693,000		
7	Plant hours connected to load	8,784		14,484		
8	Net continuous plant capability, kilowatts					
9	(a) When not limited by condenser water	516,000		700,000		
10	(b) When limited by condenser water	(1)		(1)		
11	Average number of employees	171		250		
12	Net generation, exclusive of plant use	2,509,940,640		2,186,135,200		
13	Cost of plant:					
14	Land and land rights	$ 944,825		$ 547,047		
15	Structures and improvements	3,582,955		11,744,066		
16	Equipment costs	65,641,735		141,320,229		
17	Total cost	$ 70,169,515		$ 153,611,342		
18	Cost per kw. of installed capacity (Line 5)	125		169		
19	Production expenses:					
20	Operation supervision and engineering	$ 245,507		$ 255,752		
21	Fuel (A)	27,766,705		37,546,855		
22	Coolants and water (nuclear plants only)	-		-		
23	Steam expenses	818,855		1,474,135		
24	Steam from other sources	-		-		
25	Steam transferred (Cr.)	-		(2,017,505)		
26	Electric expenses	347,332		726,497		
27	Misc. steam (or nuclear) power expenses	998,163		2,130,939		
28	Rents	15,040		17,112		
29	Maintenance supervision and engineering	506,337		585,617		
30	Maintenance of structures	304,765		1,312,342		
31	Maintenance of boiler (or reactor) plant	5,104,942		7,387,192		
32	Maintenance of electric plant	1,638,025		3,626,985		
33	Maint. of misc. steam (or nuclear) plant	370,311		763,907		
34	Total production expenses	$ 38,115,987		$ 53,809,833		
35	Expenses per net kwh (Mills—2 places)	15.19		24.61		
36	Fuel: Kind (coal, gas, oil or nuclear)	COAL	OIL	COAL	OIL	GAS
37	Unit: (Coal—tons of 2,000 lb.) (Oil—barrels of 42 gals.) (Gas—M cu. ft.) (Nuclear, indicate)	TON	BBL	TON	BBL	MCF
38	Quantity (units) of fuel burned (A)	1,372,274	13,375	1,004,361	978	5,424,875
39	Average heat content of fuel burned (B.t.u. per lb. of coal, per gal of oil or per cu. ft. of gas) *	10,061	137,657	11,049	137,550	950
40	Average cost of fuel per unit, as delivered f.o.b. plant during year	20.623	33.638	30.354	No deliveries	2.114
41	Average cost of fuel per unit burned	20.032	20.706	25.941	22.737	2.114
42	Avg. cost of fuel burned per million B.t.u.	.995	3.581	1.174	3.936	2.226
43	Avg. cost of fuel burned per kwh. net gen.	11.063		16.606		
44	Average B.t.u. per kwh. net generation	11,033		12,143		

* Nuclear, indicate unit.

(A) See Foote

Rev Ed (12-71)

Schedule 8-2

SCHAD

SCHEDULE 9

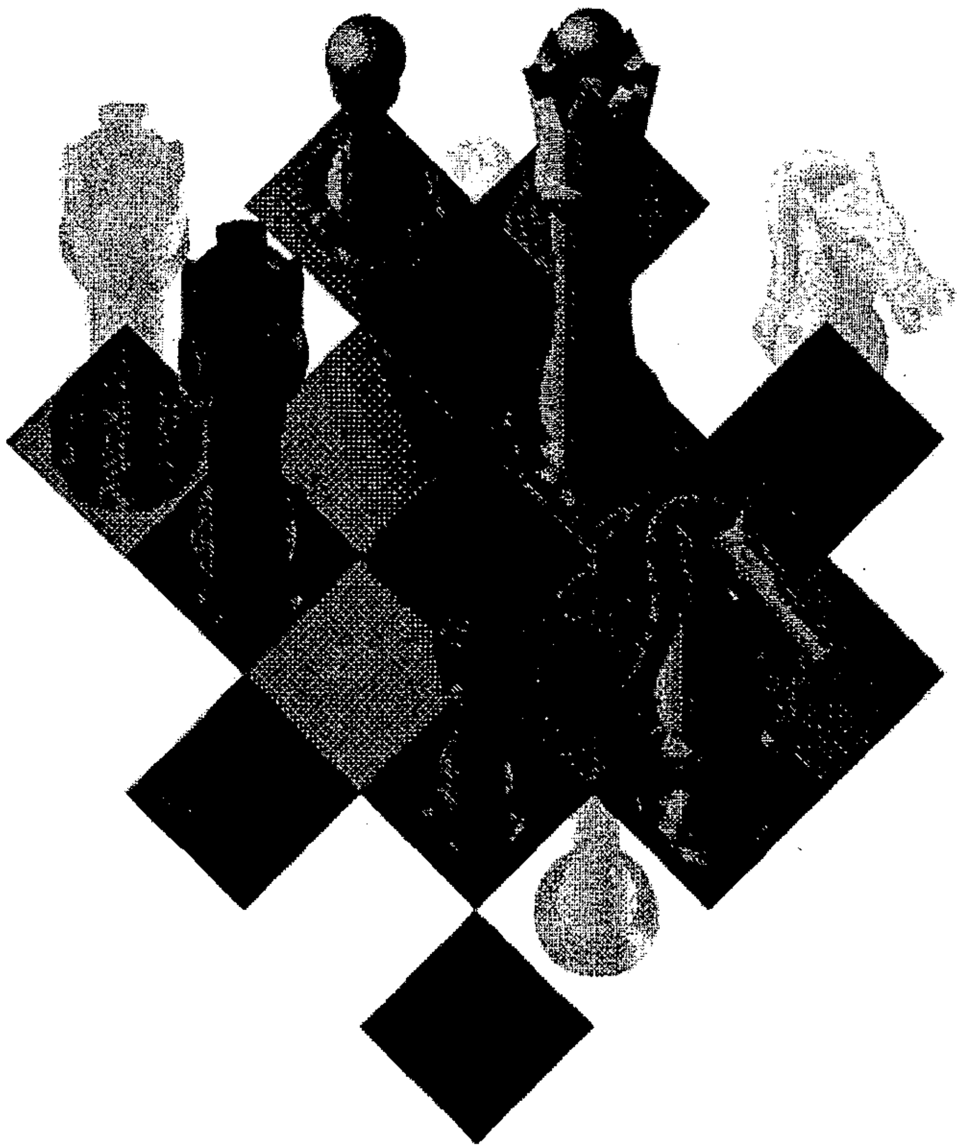
IS DEEMED

HIGHLY CONFIDENTIAL

IN ITS ENTIRETY

UIL

UIL HOLDINGS CORPORATION
2000 ANNUAL REPORT



Strategic moves - building for growth

Schedule 10-1

We're growing.

A Fair Price
Enron North America Corp., a wholly-owned subsidiary of Enron Corp., signs on to provide UI's "standard offer" service at a fixed and favorable price, as allowed by Connecticut's electric restructuring law. UI delivers a 10 percent rate reduction from 1996 prices to customers.

More Savings
Our customers see their monthly electric bills drop even more as a 1996 DPUC-approved incentive rate plan returns $19.4 million as a line item credit.

Solid Dividends
The Board of Directors remains upbeat about UIL's financial future. It reaffirms a quarterly dividend of 72 cents per share on common stock.

Reorganization
At a special meeting, our shareowners approve a proposal to reorganize UI, forming a holding company called UIL Holdings Corporation. The plan is also approved by the State Department of Public Utility Control (DPUC), the U.S. Securities and Exchange Commission and the Nuclear Regulatory Commission (NRC).

Station Sold
UI completes a purchase and sales agreement with Quinnipiac Energy LLC transferring ownership of the 75-megawatt English Station. Quinnipiac is a project-specific, limited liability company owned by three local area energy professionals. Upon DEP and Siting Council approval, it will return the station to active duty.

New Acquisitions
UIL's Precision Power Inc. (PPI) acquires The Datastore, Inc. of New Jersey, the first of several major moves this year. PPI adopts the new name "Xcelecom" to reflect its superior capabilities in specialty electrical and voice-data-video system integration services. New acquisitions follow, including The Orlando Diefenderfer Electrical Contractors of Allentown, PA; Johnson Electric of Stratford, CT; McPhee Electric Ltd., and McPhee Utility Power and Signal of Farmington, CT; and JBL Electric, Inc. of Paterson, NJ.

Divestiture
UI's 3.6% investment is valued at $32.5 million in the winning bid of $1.3 billion for the sale of the Millstone nuclear power plant complex. Upon closing in the first half of 2001, the proceeds will be used to reduce debt and improve our capitalization ratio.

Positive Ratings
UI's securities receive a "positive" ratings outlook from Moody's Investors Service, a step up from the former "stable" category. Moody's also assigns a Baa1 issuer rating with a positive outlook for UIL Holdings. Fitch upgrades UI's unsecured debt and secured lease obligations from BBB+ to A-, issuing an implied senior unsecured rating of BBB+ for UIL Holdings. Fitch's rating outlook for both UI and UIL Holdings is "stable."

Energy-Saving Efforts
Through a 13-week joint ad campaign, UI's 318,000 customers and Connecticut Light & Power's 1.1 million customers are urged to call a toll-free number for energy conservation information. UI's Client Relations Center responds to a high volume of customer inquiries.

Internal Efficiency
UI continues a comprehensive three-phase redesign of its support services processes. The expected outcome: savings, efficiencies, and cost-effective, high-value services customized for the corporation and its business units.

Going The Distance
UI's Network Meter Reading Team installs its 200,000th meter in Shelton in late December – a milestone. Once operational, the new system allows the company to read customer meters remotely.

Schedule 10-2

UI's operating expenses for operation, maintenance and purchased capacity decreased by $47.2 million in 2000 compared to 1999. The principal components of these expense changes included:

(In Millions of Dollars)	Increase/ (Decrease)
Operating Distribution Division	
Site remediation costs (Note A)	$ (9.3)
1999 fossil generating unit operation and maintenance	(7.5)
Pension and employee benefits costs	(5.2)
NEPOOL transmission expense	3.7
Other transmission	(1.3)
1999 Y2K projects	(2.7)
Other	(5.3)
TOTAL OPERATING DISTRIBUTION DIVISION	(27.6)
NUCLEAR DIVISION (NOTE B)	(4.9)
Competitive Transition Assessment (CTA)	
Purchased capacity (Note C)	(28.5)
Other	0.4
TOTAL CTA	(28.1)
CONSERVATION AND LOAD MANAGEMENT AND RENEWABLE ENERGY (NOTE D)	13.4
Total O&M expense	$(47.2)

Note (A): These costs were incurred in the fourth quarter of 1999 to repair a riparian bulkhead in New Haven and for remediation of environmental conditions at another site.

Note (B): Nuclear Division operation and maintenance expenses are incurred in the business of producing energy for the wholesale market and are reflected in the Nuclear Division results. These expenses decreased by $4.9 million in 2000 compared to 1999, due primarily to the absence of 1999 Millstone Unit 3 refueling outage costs and reductions in base expenses at both Seabrook Unit 1 and Millstone Unit 3 that more than offset the incremental costs associated with the Seabrook Unit 1 2000 outage.

Note (C): UI's wholesale purchased power agreements were assumed by Enron Power Marketing, Inc. (EPMI) as part of an agreement for EPMI to supply the power needed by UI to meet its standard offer retail customer service obligations until the end of the four-year standard offer period (the end of 2003) and the power needed to serve UI's special contract retail customers for the remaining contract terms. UI has created a regulatory asset and noncurrent liability to reflect this agreement, and the regulatory asset is being amortized as part of the Competitive Transition Assessment (CTA). The amortization for 2000 of about $26.8 million is included in the "Amortization of regulatory assets" line of the income statement.

Note (D): Conservation and load management and renewable energy costs are pass-through costs recovered in unbundled retail customer rates.

Other taxes for UI decreased by $4.3 million in 2000 compared to 1999, due in part to the sale of fossil generating units in April 1999.

Depreciation expense for UI decreased by $28.8 million in 2000 compared to 1999. About $24.5 million of this decrease was due to the reclassification of depreciation on nuclear plant stranded assets and other assets from depreciation expense to amortization of regulatory assets within the Competitive Transition Assessment (CTA). The remaining $4.3 million decrease was due primarily to the sale of fossil generating units in 1999.

On December 31, 1996, the DPUC issued an order that implemented a five-year Rate Plan to reduce UI's regulated retail prices and accelerate the recovery of certain "regulatory assets." According to the Rate Plan, under which UI is currently operating, "accelerated" amortization of past regulated utility investments is

Overall, retail revenue increased by $8.0 million in 1999 compared to 1998.

(In Millions of Dollars)	From Operations	From One-time	Total
Retail Sales Margin			
Revenue from:			
Sharing for 1999	$(14.4)	$(3.9)	$(18.3)
Estimate of "real" retail sales growth, up 3.2%	20.2	0	20.2
Estimate of weather effect on retail sales, up 1.1%	7.1	0	7.1
Sales decrease from Yale University cogeneration, (0.6)%	(3.6)	0	(3.6)
Price mix of sales and other	2.6	0	2.6
TOTAL RETAIL REVENUE	$ 11.9	$(3.9)	$ 8.0
REVENUE BASED TAXES	$ (0.6)	$ 0.1	$ (0.5)
Fuel and energy, margin effect:			
Sales increase	$ (4.7)	$ 0	$ (4.7)
Nuclear fuel prices and outage replacement power costs	(0.5)	0	(0.5)
Purchased energy prices	(15.5)	0	(15.5)
TOTAL RETAIL FUEL AND ENERGY	$(20.7)	$ 0	$(20.7)
TOTAL RETAIL SALES MARGIN	$ (9.4)	$(3.8)	$(13.2)

Net wholesale margin (wholesale revenue less wholesale expense) decreased by $10.4 million in 1999 compared to 1998, due to lower wholesale sales. Other operating revenues, which include NEPOOL related transmission revenues, increased by $6.4 million. NEPOOL transmission revenues are recoveries, for the most part, of NEPOOL transmission expense and reflect new accounting requirements implemented by the Federal Energy Regulatory Commission.

Operating expenses for operations, maintenance and purchased capacity charges decreased by $5.7 million in 1999 compared to 1998. The principal components of these expense changes include:

(In Millions of Dollars)	
Capacity expense:	
Connecticut Yankee	$(2.4)
Cogeneration and other purchases (see Note A)	1.8
TOTAL CAPACITY EXPENSE	(0.6)
Other O&M expense:	
Seabrook Unit 1 (refueling outage costs and accruals)	4.1
Millstone Unit 3 (refueling outage costs and accruals)	1.1
Other expenses at nuclear units	(0.8)
Fossil generation unit operating and maintenance costs	(23.1)
NEPOOL transmission expense	3.4
Site remediation costs (see Note B)	7.8
Other miscellaneous, including impact of generation asset sale	2.4
TOTAL O&M EXPENSE	$(5.1)

Note (A): A cogeneration facility was out of service for about a month in the first quarter of 1998 but operated normally in 1999.

Note (B): These costs were incurred to repair a riparian bulkhead in New Haven and for remediation of environmental conditions at another site. No further material expenses are currently anticipated for remediation of these sites.

Depreciation expense decreased by $12.4 million in 1999 compared to 1998, due primarily to the generation asset sale.

UIL Holdings' property, plant and equipment as of December 31, 2000 and 1999 was comprised as follows:

(In Thousands)	2000	1999
Utility:		
Nuclear Production	$269,750	$ 271,012
Transmission	152,218	148,419
Distribution	430,620	415,892
General	44,246	46,578
Future use plant	642	30,167
Other	28,499	94,997
Subtotal	925,975	1,007,065
Non-regulated business units	36,510	24,536
	$962,485	$1,031,601

See Note (C), "Rate-related Regulatory Proceedings" for a discussion of the sale by the Company of its two operating fossil-fueled generating stations and the regulatory decisions allowing for recovery of stranded costs, including the above-market investment in nuclear generating units.

DEPRECIATION Provisions for depreciation on utility plant for book purposes are computed on a straight-line basis, using estimated service lives determined by independent engineers. One-half year's depreciation is taken in the year of addition and disposition of utility plant, except in the case of major operating units on which depreciation commences in the month they are placed in service and ceases in the month they are removed from service. The aggregate annual provisions for depreciation for the years 2000, 1999 and 1998 were approximately 3.05%, 3.29% and 3.45%, respectively, of the original cost of depreciable property.

INCOME TAXES In accordance with Statement of Financial Accounting Standards (SFAS) No. 109, "Accounting for Income Taxes," UIL Holdings has provided deferred taxes for all temporary book-tax differences using the liability method. The liability method requires that deferred tax balances be adjusted to reflect enacted future tax rates that are anticipated to be in effect when the temporary differences reverse. In accordance with generally accepted accounting principles for regulated industries, UI has established a regulatory asset for the net revenue requirements to be recovered from customers for the related future tax expense associated with certain of these temporary differences.

For ratemaking purposes, UI normalizes all investment tax credits (ITC) related to recoverable plant investments except for the ITC related to Seabrook Unit 1, which was taken into income in accordance with provisions of a 1990 DPUC retail rate decision.

REVENUES Regulated utility revenues for UI are based on authorized rates applied to each customer's use of electricity. These rates are approved by the DPUC and can be changed only through formal proceedings. At the end of each accounting period, the estimated amount of revenues (less related expenses and applicable taxes) for services rendered but not billed is accrued.

Revenues from construction contracts entered into by Xcelecom, Inc., a wholly-owned subsidiary of URI, are recognized on a percentage-of-completion method. Under this method, revenue is recognized based on the percentage of costs incurred and accrued to date to the estimated total cost to complete these contracts.

CASH AND TEMPORARY CASH INVESTMENTS For cash flow purposes, UIL Holdings considers all highly liquid debt instruments with a maturity of three months or less at the date of purchase to be cash and temporary cash investments.

On August 17, 2000, UI sold English Station (a deactivated non-nuclear generating station, bordering the Mill River in New Haven) to Quinnipiac Energy LLC (QE), a privately-owned independent power producer. QE intends to reactivate the generating units at the station. Under the terms of the transaction, UI has retained a permanent right of occupancy on and over the station property for UI's existing New Haven harbor transmission line towers and cables. QE will complete the bulkhead replacement project that UI has commenced to preserve and protect the station property; and QE will assume responsibility for any and all environmental liability associated with UI's prior ownership and operation of the station. UI has agreed to pay for the cost of completing the bulkhead replacement project and has funded 61% (approximately $1.2 million) of the environmental remediation costs that will be incurred by QE under Connecticut's Transfer Act as a result of QE's acquisition of the station. UI has also paid QE $4.25 million for QE's assumption of the remaining Transfer Act remediation costs and any and all environmental liability associated with UI's prior ownership and operation of the station.

On October 1, 1998, in its "unbundling plan" filing with the DPUC under the Restructuring Act, and in other regulatory dockets, UI stated that it plans to divest its nuclear generation ownership and leasehold interests (17.5% of Seabrook Unit 1 in New Hampshire and 3.685% of Millstone Station Unit 3 in Connecticut) by the end of 2003, in accordance with the Restructuring Act. On April 19, 2000, the DPUC approved UI's plan for divesting its ownership interest in Millstone Unit 3 by participating in an auction process for all three of the generating units at Millstone Station, which was concluded on August 7, 2000, when Dominion Resources, Inc. agreed to purchase Millstone Units 1 and 2, and 93.47% of Millstone Unit 3 for $1.298 billion. The purchase price agreed to for UI's ownership interest in Unit 3, which is subject to adjustments for expenditures and eventualities prior to the date of closing on the sale, is approximately $31 million, exclusive of nuclear fuel. UI's share of the proceeds from the sale of the nuclear fuel inventory at the date of closing on the sale is estimated to be approximately $2.5 million. The sale is scheduled to be consummated on or about April 1, 2001 or as soon thereafter as all requisite regulatory approvals are received. On December 15, 2000, UI and The Connecticut Light and Power Company filed with the DPUC for its approval of their plan to divest their respective interests in Seabrook Unit 1 by an auction process. The DPUC has commenced hearings on this divestiture plan.

The 1999 DPUC decision establishing UI's standard offer rates authorized UI to recover $801 million of stranded costs through its rate structure.

Based on the decisions in the regulatory proceedings described above, the sale of UI's fossil-generation assets and the planned divestiture of its nuclear generation ownership interests by the end of 2003, UI ceased applying SFAS No. 71 to the generation portion of its assets and operations as of December 31, 1999. Based on the favorable DPUC decisions that allow full recovery, through UI's rates, of all historically incurred stranded costs, UI did not record any write-offs in connection with this event.

(D) Accounting for Phase-in Plan

UI phased into rate base its allowable investment in Seabrook Unit 1, amounting to $640 million, during the period January 1, 1990 to January 1, 1994. In conjunction with this phase-in plan, UI was allowed to record a deferred return on the portion of allowable investment excluded from rate base during the phase-in period. UI amortized the net-of-tax accumulated deferred return of $62.9 million over the five-year period that ended on December 31, 1999.

(E) Short-Term Credit Arrangements

On June 26, 2000, UI entered into a Money Market Loan arrangement with Chase Manhattan Bank. On September 29, 2000, this arrangement was transferred to UIL Holdings. This is an uncommitted short-term borrowing arrangement under which Chase Manhattan Bank may make loans to UIL Holdings for fixed maturities from one day up to six months. Chase Securities, Inc. acts as an agent and sells the loans to investors. The fixed interest rates on the loans are determined based on conditions in the financial markets at the time of each loan. As of December 31, 2000, UIL Holdings had loans totaling $59 million outstanding under this arrangement.

UNITED STATES
NUCLEAR REGULATORY COMMISSION
WASHINGTON, D.C. 20555-0001

ENTERGY ARKANSAS, INC.

ENTERGY OPERATIONS, INC.

DOCKET NO. 50-313

ARKANSAS NUCLEAR ONE, UNIT 1

FACILITY OPERATING LICENSE

License No. DPR-51

1. The Nuclear Regulatory Commission (the Commission) having previously made the findings set forth in License No. DRP-51 issued on May 21, 1974, has now found that:

   a. The application to renew License No. DRP-51 filed by Entergy Arkansas, Inc. and Entergy Operations, Inc., complies with the standards and requirements of the Atomic Energy Act of 1954, as amended (the Act), and the Commission's rules and regulations set forth in 10 CFR Chapter I and all required notifications to other agencies or bodies have been duly made;

   b. Actions have been identified and have been or will be taken with respect to (1) managing the effects of aging during the period of extended operation on the functionality of structures and components that have been identified to require review under 10 CFR 54.21(a)(1) and (2) time-limited aging analyses that have been identified to require review under 10 CFR 54.21(c), such that there is reasonable assurance that the activities authorized by the renewed license will continue to be conducted in accordance with the current licensing basis, as defined in 10 CFR 54.3, for the Arkansas Nuclear One, Unit 1, plant and that any changes made to the plant's current licensing basis in order to comply with 10 CFR 54.29(a) are in accord with the Act and the Commission's regulations;

   c. The facility will operate in conformity with the application, as amended, the provisions of the Act, and the rules and regulations of the Commission;

   d. There is reasonable assurance: (i) that the activities authorized by this renewed license can be conducted without endangering the health and safety of the public, and (ii) that such activities will be conducted in compliance with the rules and regulations of the Commission;

e. Entergy Operations, Inc. (EOI) is technically and financially qualified to engage in the activities authorized by this renewed license in accordance with the rules and regulations of the Commission;

f. Entergy Arkansas, Inc. has satisfied the applicable provisions of 10 CFR Part 140, "Financial Protection Requirements and Indemnity Agreements," of the Commission's regulations;

g. The renewal of this operating license will not be inimical to the common defense and security or to the health and safety of the public;

h. After weighing the environmental, economic, technical, and other benefits of the facility against environmental costs and considering available alternatives, the issuance of the renewed Facility Operating License No. DPR-51 is in accordance with 10 CFR Part 51 of the Commission's regulations and all applicable requirements have been satisfied; and

i. The receipt, possession, and use of source, byproduct and special nuclear material as authorized by this renewed license will be in accordance with the Commission's regulations in 10 CFR Parts 30, 40 and 70, including 10 CFR Section 30.33, 40.32, 70.23 and 70.31.

2. The renewed Facility Operating License No. DPR-51 is hereby issued to Entergy Arkansas, Inc. and Entergy Operations, Inc. to read as follows:

a. This renewed license applies to Arkansas Nuclear One, Unit 1, a pressurized water reactor and associated equipment (the facility), owned by Entergy Arkansas, Inc. The facility is located in Pope County, Arkansas and is described in the "Safety Analysis Report" (SAR) as supplemented and amended, and the Environmental Report as supplemented and amended.

b. Subject to the conditions and requirements incorporated herein, the Commission hereby licenses:

(1) Entergy Arkansas, Inc., pursuant to Section 104b of the Act and 10 CFR Part 50, to possess but not operate the facility at the designated location in Pope County, Arkansas, in accordance with the procedures and limitations set forth in this renewed license.

(2) EOI, pursuant to Section 104b of the Act and 10 CFR Part 50, "Licensing of Production and Utilization Facilities," to possess, use, and operate the facility at the designated location in Pope County, Arkansas in accordance with the procedures and limitations set forth in this renewed license;

(3) EOI, pursuant to the Act and 10 CFR Part 70, to receive, possess and use at any time at the facility site and as designated solely for the facility, special nuclear material as reactor fuel, in accordance with the limitations for storage and amounts required for reactor operation, as described in the SAR, as supplemented and amended;

(4) EOI, pursuant to the Act and 10 CFR Parts 30, 40 and 70, to receive, possess and use at any time any byproduct, source and special nuclear material as sealed neutron sources for reactor startup, sealed sources for reactor instrumentation and radiation monitoring equipment calibration, and as fission detectors in amounts as required;

(5) EOI, pursuant to the Act and 10 CFR Parts 30, 40 and 70, to receive, possess and use in amounts as required any byproduct, source or special nuclear material without restriction to chemical or physical form, for sample analysis byproduct, source or special nuclear material without restriction to chemical or physical form, for sample analysis or instrument calibration or associated with radioactive apparatus or components;

(6) EOI, pursuant to the Act and 10 CFR Parts 30 and 70, to possess, but not separate, such byproduct and special nuclear materials as may be produced by the operation of the facility.

c. This renewed license shall be deemed to contain and is subject to the conditions specified in the following Commission regulations in 10 CFR Chapter I: Part 20, Section 30.34 of Part 30, Section 40.41 of Part 40, Sections 50.54 and 50.59 of Part 50, and Section 70.32 of Part 70; is subject to all applicable provisions of the Act and to the rules, regulations, and orders of the Commission now or hereafter in effect; and is subject to the additional conditions specified or incorporated below:

(1) Maximum Power Level

EOI is authorized to operate the facility at steady state reactor core power levels not in excess of 2568 megawatts thermal.

(2) Technical Specifications

The Technical Specifications contained in Appendix A, as revised through Amendment No. 214, are hereby incorporated in the renewed license. EOI shall operate the facility in accordance with the Technical Specifications.

(3) Safety Analysis Report

The licensee's SAR supplement submitted pursuant to 10 CFR 54.21(d), as revised on March 14, 2001, describes certain future inspection activities to be completed before the period of extended operation. The licensee shall complete these activities no later than May 20, 2014.

(4) Physical Protection

EOI shall fully implement and maintain in effect all provisions of the Commission-approved physical security, guard training and qualification, and safeguards contingency plans, including amendments made pursuant to provisions of the Miscellaneous Amendments and Search Requirements revisions to 10 CFR 73.55 (51 FR 27817 and 27822) and to the authority of 10 CFR 50.90 and 10 CFR 50.54(p). The plan, which contains Safeguards Information protected under 10 CFR 73.21, is entitled: "Arkansas Nuclear One Industrial Security Plan," with revisions submitted through August 2, 1995. The Industrial Security Plan also includes the requirements for guard training and qualification in Appendix A and the safeguards contingency events in Chapter 7. Changes made in accordance with 10 CFR 73.55 shall be implemented in accordance with the schedule set forth therein.

(5) Systems Integrity

EOI shall implement a program to reduce leakage from systems outside containment that would or could contain highly radioactive fluids during a serious transient or accident to as low as practical levels. This program shall include the following:

1. Provisions establishing preventive maintenance and periodic visual inspection requirements, and

2. Integrated leak test requirements for each system at a frequency not to exceed refueling cycle intervals.

(6) Iodine Monitoring

EOI shall implement a program which will ensure the capability to accurately determine the airborne iodine concentration in vital areas under accident conditions. This program shall include the following:

1. Training of personnel,

2. Procedures for monitoring, and

3. Provisions for maintenance of sampling and analysis equipment.

(7) Secondary Water Chemistry Monitoring

A secondary water chemistry monitoring program shall be implemented to minimize steam generator tube degradation. This program shall include:

1. Identification of a sampling schedule for the critical parameters and control points for these parameters;

2. Identification of the procedures used to measure the values of the critical parameters;

3. Identification of process sampling points;

4. Procedures for the recording and management of data;

5. Procedures defining corrective actions for off-control point chemistry conditions; and

6. A procedure identifying the authority responsible for the interpretation of the data and the sequence and timing of administrative events required to initiate a corrective action.

(8) Fire Protection

EOI shall implement and maintain in effect all provisions of the approved Fire Protection Program as described in Appendix 9A to the SAR and as approved in the Safety Evaluation dated March 31, 1992, subject to the following provision:

1. AP&L [1] may proceed with and is required to complete the modifications identified in Paragraphs 3.1 through 3.19 of the NRC's Fire Protection Safety Evaluation on the facility dated August 22, 1978 and supplements thereto. These modifications shall be completed as specified in Table 3.1 of the Safety Evaluation Report or supplements thereto. In addition, the licensee may proceed with and is required to complete the modifications identified in Supplement 1 to the Fire Protection Safety Evaluation Report, and any future supplements. These modifications shall be completed by the dates identified in the supplement.

[1] The Original licensee authorized to possess, use, and operate the facility was AP&L. Consequently, certain historical references to AP&L remain in the license conditions.

2. The licensee may make changes to the approved Fire Protection Program without prior approval of the Commission only if those changes would not adversely affect the ability to achieve and maintain safe shutdown in the event of a fire.

3. This renewed license is effective as of the date of issuance and shall expire at midnight, May 20,2034.

FOR THE NUCLEAR REGULATORY COMMISSION

Samuel J. Collins, Director
Office of Nuclear Reactor Regulation

Attachment:
Appendix A - Technical Specifications
Renewed License No. DRP-51

Date of Issuance:

Status of License Renewal Applications and Ind Activities

On this page:

- Plant Applications for License Renewal
- Owner's Groups
- Industry Activities

Plant Applications for License Renewal

- Calvert Cliffs, Units 1 and 2 (includes milestones, application, and safety e report)
- Oconee Nuclear Station, Units 1, 2 and 3 (includes milestones, application evaluation report)
- Arkansas Nuclear One, Unit 1 (includes milestones, application, and safety report)
- Edwin I. Hatch, Units 1 and 2- Application received March 1, 2000
- Turkey Point, Units 3 and 4 - Application received September 11, 2000
- North Anna, Units 1 and 2, and Surry, Units 1 and 2 - Joint application rec 2001
- McGuire, Units 1 and 2, and Catawba, Units 1 and 2 - Joint application rec 2001
- Peach Bottom, Units 2 and 3 - Application received July 2, 2001
- St. Lucie, Units 1 and 2 - Application received November 30, 2001
- Fort Calhoun, Unit 1 - Application received January 11, 2002
- Future Submittals *
    - H. B. Robinson, Unit 2 - June 2002
    - Ginna - July 2002
    - V.C. Summer - August 2002
    - Dresden, Units 2 and 3 - January-March 2003
    - Quad Cities, Units 1 and 2 - January-March 2003
    - Farley, Units 1 and 2 - September 2003
    - Arkansas Nuclear One, Unit 2 - September 2003
    - Nine Mile Point, Units 1 and 2 - October 2003
    - D.C. Cook, Units 1 and 2 - November 2003
    - Browns Ferry, Units 2 and 3 - December 2003
    - Brunswick, Units 1 and 2 - January-March 2004
    - Beaver Valley, Units 1 and 2 - September 2004 (Unit 2 requires exe
    - Davis-Besse, Unit 1 - December 2004
    - Pilgrim, Unit 1 - December 2004
    - Susquehanna, Units 1 and 2 - January-March 2005
    - Cooper - April 2005

* This list of future submittals is based on the January 8, 2002, public meeting between the NRC a License Renewal Working Group and will be updated on a periodic basis.

TOP

Schedule 12

WESTERN RESOURCES, INC. - KGE
DEPRECIATION STUDY AS OF 12/31/99
MJM SCHEDULE OF INDICATED REMAINING LIFE ACCRUAL RATES

Account Number	Description	Plant Balance 12/31/1999	Disp.	ASL	Salvage Percent	Net Salvage Amount	12/31/1999 Depreciation Book Reserve	Balance To Be Recovered	Estimated Remaining Life	Annual Dep. Amount	Accrual Rate
	GORDON EVANS ENERGY CENTER										
311.00	STRUCTURES AND IMPROVEMENTS	3,911,560	FORECAST	39.6	-29.0%	(1,134,352)	2,867,408	2,178,504	16.9	128,906	3.30%
312.00	BOILER PLANT ECIUIPMENT	24,812,311	FORECAST	37.1	-29.0%	(7,195,570)	18,192,610	13,815,271	15.7	879,954	3.55%
	CEM MONITOR REPLACEMENT $	219,500	AMORTIZATION	5.0	0.0%	-	-	219,500	5.0	43,900	20.00%
	TOTAL 312.00	25,031,811				(7,195,570)	18,192,610	14,034,771		923,854	3.69%
314.00	TURBOGENERATOR UNITS	20,840,841	FORECAST	37.6	-29.0%	(6,043,844)	17,323,443	9,561,242	15.4	620,860	2.98%
315.00	ACCESSORY ELECTRIC EQUIPMENT	6,461,180	FORECAST	26.5	-29.0%	(1,873,742)	3,382,528	4,952,394	14.8	334,621	5.18%
316.00	MISC. POWER PLANT EQUIPMENT	1,046,790	FORECAST	27.3	-29.0%	(303,569)	452,274	898,085	15.9	56,483	5.40%
	TOTAL GORDON EVANS ENERGY CENTER	57,292,182				(16,551,078)	42,218,263	31,624,997		2,064,724	3.60%
	TOTAL DEPREC, STEAM PROD. PLANT	569,762,515		30.6	0.0%	(77,033,496)	329,305,315	317,490,696		13,736,563	2.41%
	NUCLEAR PRODUCTION PLANT										
	WOLF CREEK PLANT										
321.00	STRUCTURES AND IMPROVEMENTS	398,365,164	FORECAST	54.6	0.0%	-	144,178,759	254,186,405	41.2	6,169,573	1.55%
322.00	REACTOR PLANT EQUIPMENT	619,294,392	FORECAST	50.3	0.0%	-	212,213,522	407,080,870	37.9	10,740,920	1.73%
323.00	TURBOGENERATOR UNITS	165,616,704	FORECAST	46.0	0.0%	-	59,063,209	106,553,495	32.8	3,248,582	1.96%
324.00	ACCESS. ELECTRIC EQUIPMENT	131,593,734	FORECAST	52.6	0.0%	-	39,715,010	91,878,724	40.3	2,279,869	1.73%
325.00	MISC. POWER PLANT EQUIPMENT	59,956,290	FORECAST	47.4	0.0%	-	5,709,198	54,247,092	38.4	1,412,685	2.36%
	TOTAL WOLF CREEK PLANT	1,374,826,284			0.0%	-	460,879,698	913,946,586		23,851,629	1.73%
	OTHER PRODUCTION PLANT										
	JEFFREY WIND TURBINES										
341.00	STRUCTURES AND IMPROVEMENTS	10,491	FORECAST	20.0	0.0%	-	136	10,355	19.5	531	5.06%
344.00	GENERATORS	303,728	FORECAST	20.0	0.0%	-	3,819	299,909	19.5	15,380	5.06%
345.00	ACCESS. ELECTRIC EQUIPMENT	22,688	FORECAST	18.7	0.0%	-	288	22,400	18.2	1,231	5.42%
346.00	MISC. POWER PLANT EQUIPMENT	5,545	FORECAST	20.0	0.0%	-	72	5,473	19.5	281	5.06%
	TOTAL JEFFREY WIND TURBINES	342,452		19.9	0.0%	-	4,315	338,137		17,422	5.09%

WORKPAPERS

OF

GARY WEISS

MPSC CASE NO. EC-2002-1

May, 2002

AmerenUE
DEPRECIATION & AMORTIZATION EXPENSE
12 MONTHS ENDED 06/30/2001 WITH ADJUSTMENTS BASED ON 09/30/01 PLANT BALANCES
For 12 Months Ending June 30, 2001 Updated Through September 30, 2001 (4CP)

		ELECTRIC					
		POWER	ULTIMATE CONSUMERS		SALES FOR	SYSTEM	
	TOTAL	POOL	MISSOURI	ILLINOIS	RESALE	GENERAL	GAS
INTANGIBLE PLANT:							
ACCOUNT 301	$ -	$ -	$ -	$ -	$ -	$ -	$ -
ACCOUNT 303	(23,773)	-	-	-	-	(23,773)	-
TOTAL INTANGIBLE PLANT	(23,773)	-	-	-	-	(23,773)	-
PRODUCTION PLANT:							
NUCLEAR (1)	65,079,148	-	59,788,213	4,340,779	950,156	-	-
CALLAWAY POST OPERATIONAL (2)	3,687,468	-	3,612,812	- -	74,856	-	-
CALLAWAY DECOMMISSIONING (3)	6,783,000	-	6,214,184	296,589	272,227	-	-
STEAM	60,505,092	60,505,092	-	-	-	-	-
HYDRAULIC	1,865,132	1,865,132	-	-	-	-	-
OTHER	2,357,648	2,357,648	-	-	-	-	-
TOTAL PRODUCTION PLANT	140,277,488	64,727,872	69,615,009	4,637,368	1,297,239	-	-
TRANSMISSION PLANT	9,152,336	9,152,336	-	-	-	-	-
DISTRIBUTION PLANT							
MISSOURI	98,398,730	-	97,896,896	-	501,834	-	-
ILLINOIS	5,935,430	-	-	5,935,430	-	-	-
IOWA	-	-	-	-	-	-	-
TOTAL DISTRIBUTION PLANT	104,334,160	-	97,896,896	5,935,430	501,834	-	-
GENERAL PLANT							
MISSOURI	9,300,826	-	-	-	-	9,194,270	106,556
ILLINOIS	257,335	-	-	-	-	252,381	4,954
IOWA	14,304	-	-	-	-	14,304	-
TOTAL GENERAL PLANT	9,972,465	-	-	-	-	9,460,955	111,510
TOTAL DEPRC. & AMORT. - PLANT	263,312,676	73,880,208	167,511,905	10,572,798	1,799,073	9,437,182	111,510
(GAIN)/LOSS - SALE OF PROPERTY (4)	777	-	723	44	10	-	-
EMISSION ALLOWANCE (8)	-	-	-	-	-	-	-
(GAIN)/LOSS - FROM SO_2 OPTIONS (7)	(467,999)	-	(413,945)	(45,830)	(8,424)	-	-
AMORT OF MO. MERGER COSTS (6)	4,520,790	-	4,520,790	-	-	-	-
TOTAL DEPRC. & AMORT. EXPENSE	267,366,244	73,880,208	171,619,473	10,527,212	1,790,659	9,437,182	111,510
ALLOCATION TO H & G (5)	(111,510)	-	-	-	-	-	(111,510)
TOTAL ELEC. DEPRC. & AMORT. EXP. Per books	$ 267,254,734	$ 73,880,208	$ 171,619,473	$ 10,527,212	$ 1,790,659	$ 9,437,182	$ -
PRO FORMA ADJUSTMENT - SO_2 OPTIONS (9)	467,999	-	413,945	45,630	8,424	-	-
PRO FORMA ADJUSTMENT - INTANGIBLE PLANT (10)	23,773	-	-	-	-	23,773	-
EST. CHG. IN DEPRC. EXP.- NUCLEAR (1)	5,106,618	-	4,691,450	340,611	74,557	-	-
EST. CHG. IN DEPRC. EXP. - STEAM	21,356,340	21,356,340	-	-	-	-	-
EST. CHG. IN DEPRC. EXP. - HYDRO	1,484,446	1,484,446	-	-	-	-	-
EST. CHG. IN DEPRC. EXP. - OTHER PROD.	(542,377)	(542,377)	-	-	-	-	-
EST. CHG. IN DEPRC. EXP. - TRANSMISSION	961,743	961,743	-	-	-	-	-
EST. CHG. IN DEPRC. EXP. - DISTRIBUTION	(4,746,593)	-	(4,722,385)	-	(24,208)	-	-
EST. CHG. IN DEPRC EXP.- GENERAL PLANT	5,990,353	-	-	-	-	5,990,353	-
EST. CHG. IN DEPRC EXP.- ALLOCATION TO GAS (11)	(75,291)	-	-	-	-	(75,291)	-
EST. CHG. IN DEPRC.EXP.- ACCT 303 CALLAWAY SOFTWARE (12)	21,479	21,479	-	-	-	-	-
ANNUAL AMORT. OF RESERVE VAR. - NUCLEAR (1)	1,443,403	-	1,326,054	96,275	21,074	-	-
ANNUAL AMORT. OF RESERVE VAR. - STEAM	2,923,340	2,923,340	-	-	-	-	-
ANNUAL AMORT. OF RESERVE VAR. - HYDRO	665,241	665,241	-	-	-	-	-
ANNUAL AMORT. OF RESERVE VAR. - OTHER PROD.	(252,809)	(252,809)	-	-	-	-	-
ANNUAL AMORT. OF RESERVE VAR. - TRANSMISSION	123,833	123,833	-	-	-	-	-
ANNUAL AMORT. OF RESERVE VAR. - DISTRIBUTION	(1,837,584)	-	(1,828,212)	-	(9,372)	-	-
ANNUAL AMORT. OF RESERVE VAR. - GENERAL PLANT	2,852,320	-	-	-	-	2,852,320	-
PRO FORMA ELEC. DEPRC. & AMORT. EXP.	$ 303,220,968	$ 100,621,444	$ 171,500,325	$ 11,009,728	$ 1,861,134	$ 18,228,337	$ -

(1) Allocated on Nuclear allocation factor
(2) The Callaway Post Operational Costs applicable to Illinois jurisdiction were written off 12/97. Allocated on fixed factor, excluding Illinois.
(3) Directly assigned.
(4) Allocated on Net Plant
(5) Per JV PA706, December 2000
(6) Amortization per Commission order, eff. 01/04/2000. Includes one-tenth ($105,900) of $1,059,000 merger advertising.
(7) Allocated on Variable Factor
(8) Emission Allowances are currently being classified as Other Electric Revenues.
(9) SO_2 Options, as part of FAS 133, were reclassified to Miscellaneous Income.
(10) Eliminate prior period adjustment made 12/2000.
(11) Per JV PA706, December, 2000 with proposed depreciation rates less actual rates.
(12) Amortization of computer software used at Callaway Plant over 5 years.

Schedule 14-2

05/01/2002