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COMMONWEALTH OF KENTUCKY
OFFICE OF THE ATTORNEY GENERAL

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ATTORNEY GENERAL

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FRANKFORT, KY 40601-8204

March 23, 2004

Mr. Thomas M. Dorman
Executive Director
Kentucky Public Service Commission
211 Sower Boulevard
Frankfort, Kentucky 40601

RE: In the Matter Of: An Adjustment of the Electric Rates, Terms, and Conditions of Kentucky Utilities Company, PSC Case No. 2003-00434

Dear Mr. Dorman,

The Attorney General of the Commonwealth of Kentucky is filing the following testimonies in the above-styled case:

Michael M. Majoros, Jr. — three separate testimonies are filed in this case pertaining to revenue requirement, depreciation, and SFAS 143 and ARO issues. Mr. Majoros's Appendix, his statement of qualifications, is referenced in each testimony but is attached only to the depreciation testimony.

Dr. Carl Weaver

David H. Brown Kincloch

In accord with the Procedural Order of January 14, 2004, one original and ten copies of the testimonies, together with supporting schedules and exhibits, are being filed today with the Commission. A copy is also being served on all parties.

Sincerely,

Elizabeth E. Blackford
Assistant Attorney General

Cc: parties of record

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

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PUBLIC SERVICE COMMISSION

In the Matter of:

AN ADJUSTMENT OF THE ELECTRIC RATES, TERMS AND CONDITIONS OF KENTUCKY UTILITIES COMPANY	)))	CASE NO. 2003-00434

DIRECT TESTIMONY AND EXHIBITS OF MICHAEL J. MAJOROS, JR. (REVENUE REQUIREMENTS)

On Behalf of the Office Of Rate Intervention Of The Attorney General Of The Commonwealth Of Kentucky

March 23, 2004

Kentucky Utilities Company
Case No. 2003-00434 Electric Rate Case
Direct Testimony of Michael J. Majoros, Jr. (Revenue Requirements)

Table of Contents

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME, POSITION AND BUSINESS ADDRESS.

A. My name is Michael J. Majoros, Jr. I am Vice President of Snavely King Majoros O'Connor & Lee, Inc. ("Snavely King"). My business address is 1220 L Street, N.W., Suite 410, Washington, D.C. 20005.

Q. PLEASE DESCRIBE SNAVELY KING.

A. Snavely King is an economic consulting firm founded in 1970 to conduct research on a consulting basis into the rates, revenues, costs and economic performance of regulated industries and firms. The firm has a professional staff of 15 economists, accountants, engineers and cost analysts. Much of its work involves the development, preparation and presentation of expert witness testimony before federal and state regulatory agencies. Over the course of its 33-year history, members of the firm have participated in over 1000 proceedings before almost all of the state and all federal Commissions that regulate utilities or transportation industries.

Q. HAVE YOU ATTACHED A SUMMARY OF YOUR QUALIFICATIONS AND EXPERIENCE?

A. Yes, Appendix A contains a summary of my qualifications and experience. It also includes a listing of my appearances before regulatory bodies.

Q. FOR WHOM ARE YOU APPEARING IN THIS PROCEEDING?

A. I am appearing on behalf of the Attorney General of the Commonwealth of Kentucky ("the AG").

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The purpose of this testimony is to present to the Kentucky Public Service Commission ("KPSC" or the "Commission") the AG's position on the appropriate test year revenue requirement of the Kentucky Utilities Company ("KU" or "the Company") and, by comparing that requirement with the appropriate test year revenue at present rates, to identify the overall rate adjustment needed to match test year revenue with test year revenue requirements.

In determining the AG's recommended capital structure and overall rate of return, I have relied on and incorporated the recommendations of Dr. Carl Weaver concerning the appropriate capital structure ratios, cost rates for debt, preferred stock, the return on common equity, and the resulting overall rate of return for the Company in this proceeding;

II. SUMMARY AND CONCLUSIONS

Q. PLEASE SUMMARIZE YOUR FINDINGS AND CONCLUSIONS IN THIS CASE.

A. As shown on Exhibit MJM-1 to this testimony, I find that the overall revenue deficiency presented by KU of $58.3 million is overstated by more than $55.6 million.[1] I conclude that KU's rates should be increased by less than $2.6 million.

III. RATE OF RETURN

Q. WHAT RATE OF RETURN ARE YOU USING TO DEVELOP YOUR RECOMMENDED REVENUE REQUIREMENTS?

A. Dr. Weaver has informed me that, based on his review and analysis, he has found reasonable the Company's proposed short term debt cost rate of 1.06%, A/R securitization rate of 1.39%, long term debt rate of 3.12%, preferred stock cost rate of 5.68% and a return on equity range of 9.75% - 10.25%, with a mid-point of 10.00%. These recommended capital cost rates, together with Dr. Weaver's recommended capital structure ratios that I will discuss next, produce the AG's recommended overall rate of return for KU's electric operations of 6.59%.

IV. MINIMUM PENSION LIABILITY

Q. PLEASE SUMMARIZE THE COMPANY'S PROPOSAL WITH RESPECT TO THE MINIMUM PENSION LIABILITY IN THIS CASE.

[1] AG recommended adjustments are calculated using a State Income Tax rate of 7.87% as explained in the Direct Testimony of Robert J. Henkes. The re-statement of KU's proposed pro forma after tax operating income will result in an additional adjustment as shown on Exhibit MJM-2.

A. The Company is proposing to reverse actual write-downs to its common equity balance that were previously recorded by KU in accordance with SFAS 130, *Reporting Comprehensive Income*, in order to reflect the Company's Minimum Pension Liability ("MPL"). As shown on Rives Exhibit 2, column (8), this proposal has the effect of increasing the Company's proposed adjusted electric capital structure by $10,462,375. I understand that this proposed common equity adjustment would only be possible if the Company is allowed to establish a regulatory asset for the amount of the MPL equity write-down. Therefore, the Company in this case is also requesting approval from the KPSC to record such a regulatory asset. The Company claims that the establishment of the MPL regulatory asset is consistent with and allowed by SFAS 71.

Q. WHAT IS THE AG'S RECOMMENDATION WITH RESPECT TO THIS PROPOSED ADJUSTMENT?

A. I have conferred with Robert Henkes, the AG's expert accounting witness in the LG&E Case No. 2003-00433, and we agree that Rives' adjustment should be rejected for several reasons. First, the equity write-down was actually made on the Company's books in accordance with generally accepted accounting rules and therefore represents an actual, known and measurable capitalization element as of September 30, 2003, the end of the test year in this case. In this regard, it should be noted that in the prior electric rate case of KU's sister company, LG&E, Case No. 98-426, the Commission similarly rejected a proposal to reverse for ratemaking purposes certain common equity write-downs that were actually booked by the Company during the test year in that case.[2] On page 65 of its Order in Case No. 98-426, the Commission stated in this regard:

> The Commission cannot simply ignore the fact that the write-off has occurred and will continue to affect LG&E's capitalization in the future.

Thus, my recommendation to reject the Company's proposed equity write-down reversal in the current case is consistent with previously established Commission ratemaking policy.

Second, it is by no means certain that the establishment of a regulatory MPL asset is consistent with and allowed by SFAS 71. In its testimony and responses to data requests, KU states that the regulatory MPL asset would only be extinguished through *balance sheet* accounting (i.e., changes in asset values). SFAS 71 on the other hand envisions the recovery of deferred expenses through rates, which implies an *income statement* orientation. Moreover, under SFAS 71, it is the action of the regulator, not exogenous economic forces, that makes the recovery of the regulatory asset possible. All of this raises a question in my mind as to whether the proposed regulatory asset meets the definition of the type of cost to which SFAS 71 is intended to apply.

Finally, it is possible the establishment of a regulatory asset pursuant to SFAS 71 may give rise to a presumption that the underlying

[2] Case No. 98-426, KPSC Order at 64-65.

costs are recoverable from ratepayers without a prudence review of these costs in the future.

For example, if the regulatory MPL asset balance is not eventually eliminated through the normal operation of SFAS 87 accounting, that in turn could lead to a claim for amortization through rates in a future KU rate proceeding, as has been the treatment afforded all previous and existing regulatory assets by the KPSC for KU. I am aware of at least one other case where the utility is proposing just such an amortization.[3]

Q. WHAT IS THE EFFECT OF RESTORING THE WRITEDOWN OF EQUITY CAPITAL?

A. Exhibit MJM-3 presents the revised capital structure with the MPL write-down restored. The effect is relatively minor, reducing the equity proportion of the capital structure from 52.06 percent to 51.67 percent.

Q. WHAT IS THE OVERALL COST OF CAPITAL USING THIS REVISED CAPITAL STRUCTURE?

A. As shown on Exhibit MJM-3, the overall cost of capital is 6.59 percent.

V. RATE BASE

Q. WHAT ADJUSTMENTS DO YOU RECOMMEND TO THE COMPANY'S ORIGINAL COST RATE BASE?

A. I recommend two adjustments to the original cost rate base, as quantified

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[3] See Michigan P.S.C. Case No. 13808, Application of the Detroit Edison Company, Testimony of Daniel G. Brudzynski. 7 T 895 et.seq.

in Rives Exhibit 3, page 1, to match adjustments made to the Company's capitalization in Rives Exhibit 2. They include removal of $5,469,020 in capitalized repairs to the E.W. Brown station for which the Company will be reimbursed and $1,221,169 in investment in the soon to be retired Green River Units 1 and 2. If these investments should be removed from the liabilities side of the Company's balance sheet, they should likewise be removed from the asset side.

Additionally, I recommend reductions in cash working capital to reflect the removal of Environmental Surcharge expenses and Demand Side Management expenses. Both of these elements are covered by cost recovery mechanisms separate and apart from base rates. The Company's practice is to use 1/8th of annual expense as a cash working capital allowance in the rate base. The adjustments to rate base are therefore as follows:

	Expense Reduction	Working Capital Reduction
Environmental Surcharge	($248,468)	($ 31,058)
DSM Expenses	(2,946,471)	(368,309)
		($399,367)

Total rate base adjustments are as follows:

E.W. Brown Repairs	($5,469,020)
Green River 1 and 2	(1,221,169)
Cash Working Capital	(399,367)
	($7,089,556)

VI. WEATHER NORMALIZATION

Q. WHY DO YOU RECOMMEND A WEATHER NORMALIZATION ADJUSTMENT?

Exhibit MJM-4 is a page taken from the web site of the National Oceanographic and Atmospheric Administration ("NOAA"), once known as the Weather Bureau. This table lists the "cooling degree days" for the years 2002 and 2003 by state. A cooling degree day is the difference between the mean daily temperature and 65° Fahrenheit. At the bottom of the page is the Commonwealth of Kentucky. The tabulation shows not only the cooling degree days but the extent to which the recorded degree days differ from normal. The years 2002 and 2003 show dramatically different variances from normal:

	Cooling Degree Days	
	2002	2003
June	111.2%	77.9%
July	117.6%	86.5%
August	121.5%	94.8%
September	125.8%	91.8%

In this case, KU is using a test year ending September 30, 2003, which means that it has captured the effect of an unusually cool summer, one during which customers used somewhat less electric power for air conditioning than they would have had the weather been normal. As a result, KU's revenues are understated relative to normal conditions. It is therefore appropriate for adjust the Company's test year revenues for this abnormal condition.

Q. WHAT IS THE NATURE OF THIS ADJUSTMENT?

A. There are two revenue effects from an abnormally cool summer. First, the Company's retail customers consume less electricity. Second, because of the lower retail demand, the Company is able to sell more electricity into its wholesale markets. Both of these effects should be reflected in the weather normalization revenue adjustment.

Q. HOW HAVE YOU QUANTIFIED THE WEATHER NORMALIZATION REVENUE ADJUSTMENT?

A. Exhibit MJM-5 shows this adjustment. KU's September 30, 2003 Form 10Q report to the Securities and Exchange Commission ("SEC") shows the differences in electric revenues during the three months of July, August and September in 2002 versus 2003. It also identifies the reasons for the differences. Consistent with NOAA's degree day report, the 10Q report shows that "variations in sales volume and other" resulted in 2003 revenues being $8,956,000 less than 2002 revenue during the corresponding quarter. The 10Q report also shows that wholesale sales were $4,182,000 more in 2003 relative to the corresponding months in 2002.

It would be inappropriate to adjust KU's revenue for the entire difference in revenues because the summer of 2002 was hotter than normal. Revenues during 2002 were abnormally high, just as they were abnormally low during the summer of 2003. For this reason, I have taken half the revenue differences between the two years as the basis for my adjustment. As shown on Exhibit MJM-5, one half the difference in retail and wholesale revenue comes to $5,787,000. This amount must be adjusted further for the corresponding differences in fuel and purchased power expense. I calculate a system-wide gross margin on electric sales of 53.19 percent. When applied to the $5,787,000 difference in gross revenues between 2003 and normal weather sales, the net revenue adjustment comes to $3,078,000.

VII. PENSION AND OPEB EXPENSES

Q. WHAT IS KU SEEKING FOR EMPLOYEE PENSIONS AND OTHER POST-EMPLOYMENT BENEFITS EXPENSE?

A. KU's total pension and Other Post-Employment Benefits ("OPEBs") expense during the test year were $9,079,136.

Q. IS KU SEEKING AN ADJUSTMENT FOR THESE EXPENSES?

A. Yes. KU is seeking an out-of-period adjustment of $3,014,859 to reflect the total pension and OPEB expense that it is recognizing for calendar year 2003. When added to the amount already recorded in Operating and Maintenance ("O&M") expense, the total cost of pensions and OPEBs is $12,093,996. This is the Kentucky jurisdictional portion of the total Company expense for 2003 of $13,615,378.

Q. WHAT ARE THE COMPONENTS OF THIS $13.6 MILLION?

A. The components of this $13.6 million were developed by the Company's actuarial consultants (Mercer) and are presented in Exhibit MJM-6. I have separated the pension costs into their constituent elements. They are:

- "Service costs," which are the projected benefits earned by active employees during the current period on a present value basis,
- "Interest costs," representing the year's accretion in the present value of the Projected Benefit Obligation ("PBO"),
- Amortization of "prior service costs," that result from changes in the benefit plans that increase the PBO for existing employees and that are amortized over the remaining service years of the affected employees,
- Amortization of "transition (gain) or obligation" that results from changes in the accounting rules,
- Amortization of actuarial (gain) or loss, which I assume to be changes in the ABO due to revisions in predicted retirement periods of the Company's employees,
- Offset by the expected return on the assets in the pension fund.

Q. HOW DO THE 2003 PENSION COSTS COMPARE WITH THOSE IN 2002?

I have included the 2002 pension expenses on Exhibit MJM-6. This exhibit reveals that KU's 2002 pension costs were $1.65 million, and that in 2003 they were $6.03 million, a 3.7 fold increase. The pension costs of LG&E Service Company increased from $5.37 million to $6.67 million, or 24 percent.

Q. DO OPEB EXPENSES HAVE THE SAME ELEMENTS AS PENSION EXPENSES?

A. Yes, they do. However, I do not have a breakdown of the OPEB expenses, nor do I have the 2002 costs. I suspect that they have shown very similar degree of volatility between the two years.

Q. WHAT ACCOUNTS FOR THE VOLATILITY OF THESE COSTS?

A. Two factors account for this volatility of these costs. The first is the interest rate, and the second is the value of the assets in the pension fund.

Q. WHY DOES THE INTEREST RATE CREATE VOLATILITY IN PENSION COSTS?

A. Mercer, KU's consultants, selects the interest rate each year based on current yields on corporate bonds. In 2002, the interest rate was 6.75 percent, and in 2003 it was reduced to 6.25 percent. When the interest rate is reduced, the present value of the Projected Benefit Obligation ("PBO") and the Accumulated Benefit Obligation ("ABO") increase. When the present value of the PBO increases, the service costs increase. The more the present value of the ABO increases, the more it exceeds the asset value of the pension fund when, as in KU's case, there is an under-funding of the pension obligation. Also, a lower interest rate has the counter-intuitive effect of increasing the interest costs on the ABO. That is because as the present value of the ABO increases, the annual accretion in that value is correspondingly larger, even at the lower interest rate.

Q. WHY DOES THE ASSET VALUE OF THE PENSION AND OPEB FUNDS CREATE VOLATILITY IN THESE COSTS?

A. The change in the asset value is reflected in the return on the assets because part of that return is capital gain or loss. This return is a direct offset to all of the other pension costs. Also, changes in the asset value of the pension fund affect the differential between that value and the present value of the ABO. If the asset value falls, that differential increases.

Q. WHAT IS THE LIKELY FUTURE TREND IN INTEREST RATES?

A. Interest rates on high-grade corporate bonds are currently at a 37-year low.[4] Given the size of both the Federal budget deficit and the national trade deficit, it is unlikely that these very low interest rates can continue indefinitely into the future. On December 9, 2003, the economic research firm Macroeconomic Advisors released its 10-year forecasts of national product, income, inflation and interest rates. It forecasts a slow but steady increase in interest rates throughout the coming decade, as follows:[5]

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[4] See http://www.federalreserve.gov/releases/h15/data/m/aaa.txt

[5] Macroeconomic Advisers, LLC, "Long-Term Economic Outlook", December 9, 2003.

Bonds	10-year Treasury Bonds	Bond Yields Aaa Corporate
2003	4.01%	5.66%
2004	4.56%	5.74%
2005	5.27%	6.36%
2006	5.75%	6.84%
2007	5.86%	6.95%
2008	5.97%	7.06%
2009	6.01%	7.10%
2010	6.09%	7.18%
2011	6.11%	7.20%
2012	6.14%	7.23%

Q. WHAT IS THE LIKELY TREND IN THE VALUE OF KU'S PENSION AND OPEB FUND ASSETS?

A. During the coming years, that value will probably increase. That is because most companies do not fully revalue their pension assets each year. Rather, they use a "smoothing" technique in which only one-third of each year's gain or loss is recognized in calculating the capital gains or losses in the funds' asset values. The remaining two-thirds are amortized into the revaluation over the next two years.

As everyone knows, returns on both equity and debt investments were poor during the years 2001 and 2002. If KU uses the three-year smoothing technique, then the poor returns of those years will be recognized in the return calculations only over the next two years. If the markets continue to improve, as they have over the past year, then the asset value of KU's pension funds should increase, which will increase the returns and narrow the gap between those funds' values and the ABOs.

Thus, even if there is no further increase in the value of the funds' assets during 2004 and 2005, the valuation of those funds for purposes of computing pension expense should increase. Only if the securities markets decline to the same extent as they did during 2001 and 2002 will the funds fail to display a gain for purposes of calculating pension expense at the end of 2004 and 2005.

Q. WHAT DO YOU CONCLUDE REGARDING THE FUTURE OF KU'S PENSION AND OPEB EXPENSE?

A. I conclude that if interest rates rise as predicted, the present value of KU's PBOs and ABOs will decline, reducing both service costs and interest costs, and closing the gap between the ABOs and the funds' asset values. That gap should also reduce owing to the increase in the computed value of the asset value of the funds resulting from the full amortization of the poor market performance inherited from 2001 and 2002. It thus appears that the pension and OPEB costs computed for 2003 may be the peak costs that KU has experienced and that it will experience in the immediate future.

Q. WHAT IS THE RELEVANCE OF THESE OBSERVATIONS FOR THIS RATE CASE?

A. The relevance is that KU is locking into its base rates a very high level of pension and OPEB expense which will very probably decline in the immediately following years.

Q. WHAT IS THE APPROPRIATE RESOLUTION OF THIS PROBLEM?

A. The appropriate resolution is to deny KU's out-of-period increase in pension and OPEB costs of $3,014,859. The Commission should allow only the test year expense of $9,079,136. This treatment would be consistent with the Commission's finding in LG&E's gas rate case, Case No. 2000-080.[6]

VIII. DEPRECIATION EXPENSE

Q. WHAT ADJUSTMENT DO YOU RECOMMEND TO KU'S DEPRECIATION EXPENSE?

A. In separately filed testimony, I have determined that KU's depreciation expense should be reduced by $28.9 million, as shown on MJM-7.

IX. FAS-143 ADJUSTMENT

Q. WHAT ADJUSTMENTS DO YOU RECOMMEND TO KU's FILING WITH RESPECT TO FAS-143?

A. In separately filed testimony, I have recommended that KU's $8,434,618 FAS-143 adjustments should be disallowed. The impact on KU's pro forma after tax operating income is calculated on Exhibit MJM-8.

X. OTHER EXPENSE ISSUES

Q. IN THE PARALLEL LOUISVILLE GAS AND ELECTRIC COMPANY ("LG&E") ELECTRIC RATE CASE, AG WITNESS HENKES HAS IDENTIFIED CERTAIN ISSUES THAT HAVE NOT BEEN ADDRESSED

[6] Order, Case No. 2000-080, September 27, 2000, page 35.

BY YOU IN THIS KU RATE CASE. WHAT IS YOUR RECOMMENDED POSITION ON THIS?

A. Consistency would dictate that the two companies be treated for ratemaking purposes in like fashion and I would encourage the Commission to do so. To the extent that KU has treated its expenses and revenues as LG&E has done, the same adjustments to expenses and revenues recommended by Mr. Henkes should be adopted for KU.

XI. CONCLUSION

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes, it does.

In the Matter of:

AN ADJUSTMENT OF THE ELECTRIC RATES, TERMS AND CONDITIONS OF KENTUCKY UTILITIES COMPANY	)))	**CASE NO: 2003-00434**

AND

AN ADJUSTMENT OF THE GAS AND ELECTRIC RATES, TERMS AND CONDITIONS OF LOUISVILLE GAS AND ELECTRIC COMPANY	)))	**CASE NO: 2003-00433**

AFFIDAVIT

Comes the affiant, Michael Majoros, Jr., and being duly sworn states that the foregoing testimony and attached schedules were prepared by him or under his direction and supervision and are, to the best of his information and belief, true and correct.

Washington,
District of Columbia

Subscribed and sworn to before me by the Affiant Michael Majoros, Jr. this the 22nd day of March, 2004.

Notary Public, Washington, D.C.
My Commission Expires: 3-14-06

KENTUCKY UTILITIES COMPANY
ELECTRIC RATE CASE
SUMMARY OF REVENUE REQUIREMENT POSITIONS
($000)

	KU (1) (a)	Adjustments (b)	AG (c)	
1. Capital Structure	$ 1,318,125	$ (10,462)	$ 1,307,663	Exhibit___(MJM-3)
2. Rate of Return	7.25%		6.59%	Exhibit___(MJM-3)
3. Income Requirement	95,564		86,240	
4. Pro Forma Income	60,966	23,703	84,669	Exhibit___(MJM-2)
5. Income Deficiency	34,598		1,571	
6. Revenue Conversion Factor	0.59391614		0.59637596	(2)
7. Overall Revenue Deficiency	$ 58,254	$ (55,619)	$ 2,635	

Sources:

(1) Rives Exhibits 1, 2 and 7

(2)

	KU	AG	
Revenues	100.000000	100.000000	
Less: Bad Debt and PSC Fees	(0.412300)	(0.412300)	
	99.587700	99.587700	
Less: State Income Tax @ 8.25%	(8.215985)	(7.837552)	State Income Tax @ 7.87%
	91.371715	91.750148	
Less: Federal Income Tax @ 35%	(31.980101)	(32.112552)	
Revenue Conversion Factor	59.391614	59.637596	

KENTUCKY UTILITIES COMPANY
ELECTRIC RATE CASE
SUMMARY OF PRO FORMA OPERATING INCOME POSITIONS
($000)

		KU		
1.	KU's Proposed Pro Forma After-Tax Operating Income:	$ 60,966	*	Rives Exh. 1, p.3
	<u>AG-RECOMMENDED ADJUSTMENTS:</u>			
2.	Impact of Re-Stating KY Income Taxes Included in Line 1 From Rate of 8.25% to Effective Rate of 7.87%	To be Calculated by KU		
3.	Weather Adjustment	1,836		Exhibit___(MJM-5)
4.	Pension/OPEB Adjustment	1,798		Exhibit___(MJM-6)
5.	Depreciation Expense Adjustment	15,039		Exhibit___(MJM-7)
6.	FAS-143 Adjustment	5,030		Exhibit___(MJM-8)
7.	Total AG-Recommended Adjustments	$ 23,703		
8.	Adjusted Pro Forma After-Tax Operating Income: (L 1 + L7)	$ 84,669		

* This after-tax operating income amount is calculated based on KY state income taxes of 8.25%. These KY income taxes must be re-stated at a rate of 7.87%

KENTUCKY UTILITIES COMPANY
ELECTRIC RATE CASE
COST OF CAPITAL - SEPTEMBER 30, 2003

	Per Company (a)	Reverse MPL Adjustment (b)	AG Capital Structure (c)	Adjusted Capital Structure (d)	AG Cost Rate (e)	Cost of Capital (f)
1. Short-term Debt	77,825,772		77,825,772	5.95%	1.60%	0.10%
2. A/R Securitization	38,856,247		38,856,247	2.97%	1.39%	0.04%
3. Long Term Debt	483,733,595		483,733,595	36.99%	3.12%	1.15%
4. Preferred Stock	31,531,735		31,531,735	2.41%	5.68%	0.14%
5. Common Equity	686,177,634	(10,462,375)	675,715,259	51.67%	10.00%	5.17%
6. Total Capitalization	1,318,124,983		1,307,662,608	100.00%		6.59%

KENTUCKY UTILITIES COMPANY
ELECTRIC RATE CASE
WEATHER NORMALIZATION ADJUSTMENT
($000)

			Total Company	Kentucky Allocator Rives Ex 1 Sch. 1.38	Kentucky Jurisdiction
			(a)	(b)	(c)
1.	Increase in Revenue Due to Volume	3rd Q, 03 10-Q, p.23	$ 8,956	86.094%	$ 7,711
2.	Increase in Wholesale Revenue	"	4,182	92.405%	3,864
3.	Total		13,138		11,575
4.	Normalization at one-half				5,787
5.	Total Operating Revenue	Sept 03, Mgt Rpt.	657,583		
6.	Fuel		201,264		
7.	Purchased Power		106,549		
8.	Total		307,814		
9.	Gross Margin				53.19%
10.	Weather Normalization Adjustment				$ 3,078
11.	Operating Income Impact (L.10 x .59637596)				$ 1,836

KENTUCKY UTILITIES COMPANY
ELECTRIC RATE CASE
PENSION AND OTHER POST-EMPLOYMENT BENEFITS

Pensions	Kentucky Utilities		Service Company		Total 2003
	2003	2002	2003	2002	
	(a)	(b)	(c)	(d)	(e)
1. Service Cost	2,962,008	2,636,363	4,121,069	3,542,873	
2. Interest Cost	15,924,515	16,597,319	5,057,617	4,534,624	
3. Expected Return on Plan Assets	(14,887,954)	(18,405,501)	(4,280,985)	(3,727,368)	
4. Amortization of Prior Service Costs	957,060	955,622	314,797	247,432	
5. Amortization of Transitional (gain) or Obligation	(132,893)	(132,893)			
6. Recognized actuarial (gain) or loss	1,211,041		1,460,240	769,677	
7. Total Pension	$ 6,033,777	$ 1,650,910	$ 6,672,738	$ 5,367,238	
8. Percent of Pension in O&M Expense	70.1%		76.7%		
9. O&M Expense	$ 4,228,179		$ 5,117,093		
10. Percent Servco			40.4%		
11. Total Allocable to KU O&M Expense	$ 4,228,179		$ 2,066,825		
Other Post-Employment Benefits ("OPEBs")					
12. Total from Mercer	9,754,158		2,081,735		
13. Percent OPEB in O&M Expense	68.2%		78.5%		
14. O&M Expense	$ 6,655,812		$ 1,634,741		
15. Percent Servco			40.7%		
16. Total Allocable to KU O&M Expense	$ 6,655,812		$ 664,562		
17. Total Pension and OPEB O&M Expense	$ 10,883,991		$ 2,731,387		$ 13,615,378
18. Test Year Pension & OPEB Expense					$ 10,221,260
19. Total Adjustment					$ 3,394,118
20. Kentucky Jurisdiction @ 88.826%					$ 3,014,859
21. Operating Income Impact (L.22 x .59637596)					$ 1,797,989

Sources: KU Response to AG Question 16(e)
KU Response to AG Question 61

KENTUCKY UTILITIES COMPANY
ELECTRIC RATE CASE
DEPRECIATION EXPENSE ADJUSTMENT
($000)

	KU (a)	Adjustments (b)	AG (c)
1. Annualized Depreciation Expense With New Rates	$ 103,304 (1)		$ 74,418 (2)
2. Test Year Per Books Depr. Exp. Excluding ARO and ECR	100,908		100,908
3. Depreciation Expense Change	2,396	(28,886)	(26,490)
4. Kentucky Jurisdiction	87.299%		87.299%
5. Kentucky Jurisdictional Adjustment	$ 2,092	(25,217)	$ (23,126)
6. Composite After-Tax Income Factor		0.596376	
7. Impact on After-Tax Operating Income		$ 15,039	

(1) Rives Exhibit 1, Schedule 1.11
(2) Testimony of Michael Majoros

KENTUCKY UTILITIES COMPANY
ELECTRIC RATE CASE
FAS-143 ADJUSTMENT

1. FAS-143 Adjustment	$ 8,434,618
2. Composite After-Tax Income Factor	0.596376
3. Operating Income Impact (L1 * L2)	5,030,203

Source:
L1 - Rives Exhibit 1, Schedule 1.25, Line 5.

Experience

Snavely King Majoros O'Connor & Lee, Inc.

Vice President and Treasurer (1988 to Present)
Senior Consultant (1981-1987)

Mr. Majoros provides consultation specializing in accounting, financial, and management issues. He has testified as an expert witness or negotiated on behalf of clients in more than one hundred thirty regulatory proceedings involving telephone, electric, gas, water, and sewerage companies. Mr. Majoros has appeared before Federal and state agencies. His testimony has encompassed a wide variety of complex issues including taxation, divestiture accounting, revenue requirements, rate base, nuclear decommissioning, plant lives, and capital recovery. Mr. Majoros has also provided consultation to the U.S. Department of Justice.

Mr. Majoros has been responsible for developing the firm's consulting services on depreciation and other capital recovery issues into a major area of practice. He has also developed the firm's capabilities in the management audit area.

Van Scoyoc & Wiskup, Inc., *Consultant (1978-1981)*

Mr. Majoros performed various management and regulatory consulting projects in the public utility field, including preparation of electric system load projections for a group of municipally and cooperatively owned electric systems; preparation of a system of accounts and reporting of gas and oil pipelines to be used by a state regulatory commission; accounting system analysis and design for rate proceedings involving electric, gas, and telephone utilities. Mr. Majoros also assisted in an antitrust proceeding involving a major electric utility. He submitted expert testimony in FERC Docket No. RP79-12 (El Paso Natural Gas Company). In addition, he co-authored a study entitled Analysis of Staff Study on Comprehensive Tax Normalization that was submitted to FERC in Docket No. RM 80-42.

Handling Equipment Sales Company, Inc.

Treasurer (1976-1978)

Mr. Majoros' responsibilities included financial management, general accounting and reporting, and income taxes.

Ernst & Ernst, *Auditor (1973-1976)*

Mr. Majoros was a member of the audit staff where his responsibilities included auditing, supervision, business systems analysis, report preparation, and corporate income taxes.

University of Baltimore - *(1971-1973)*

Mr. Majoros was a full-time student in the School of Business.

During this period Mr. Majoros worked consistently on a part-time basis in the following positions: Assistant Legislative Auditor – State of Maryland, Staff Accountant – Robert M. Carney & Co., CPA's, Staff Accountant – Naron & Wegad, CPA's, Credit Clerk – Montgomery Wards.

Central Savings Bank, *(1969-1971)*

Mr. Majoros was an Assistant Branch Manager at the time he left the bank to attend college as a full-time student. During his tenure at the bank, Mr. Majoros gained experience in each department of the bank. In addition, he attended night school at the University of Baltimore.

Education

University of Baltimore, School of Business, B.S. – Concentration in Accounting

Professional Affiliations

American Institute of Certified Public Accountants
Maryland Association of C.P.A.s
Society of Depreciation Professionals

Publications, Papers, and Panels

"Analysis of Staff Study on Comprehensive Tax Normalization," FERC Docket No. RM 80-42, 1980.

"Telephone Company Deferred Taxes and Investment Tax Credits – A Capital Loss for Ratepayers," Public Utility Fortnightly, September 27, 1984.

"The Use of Customer Discount Rates in Revenue Requirement Comparisons," Proceedings of the 25th Annual Iowa State Regulatory Conference, 1986

"The Regulatory Dilemma Created By Emerging Revenue Streams of Independent Telephone Companies," Proceedings of NARUC 101st Annual Convention and Regulatory Symposium, 1989.

"BOC Depreciation Issues in the States," National Association of State Utility Consumer Advocates, 1990 Mid-Year Meeting, 1990.

"Current Issues in Capital Recovery" 30th Annual Iowa State Regulatory Conference, 1991.

"Impaired Assets Under SFAS No. 121," National Association of State Utility consumer Advocates, 1996 Mid-Year Meeting, 1996.

"What's 'Sunk' Ain't Stranded: Why Excessive Utility Depreciation is Avoidable," with James Campbell, Public Utilities Fortnightly, April 1, 1999.

"Local Exchange Carrier Depreciation Reserve Percents," with Richard B. Lee, Journal of the Society of Depreciation Professionals, Volume 10, Number 1, 2000-2001

Michael J. Majoros, Jr.

Federal Regulatory Agencies

Date	Agency	Docket	Utility
1979	FERC-US 19/	RR79-12	El Paso Natural Gas Co.
1980	FERC-US 19/	RM80-42	Generic Tax Normalization
1996	CRTC-Canada 30/	97-9	All Canadian Telecoms
1997	CRTC-Canada 31/	97-11	All Canadian Telecoms
1999	FCC 32/	98-137 (Ex Parte)	All LECs
1999	FCC 32/	98-91 (Ex Parte)	All LECs
1999	FCC 32/	98-177 (Ex Parte)	All LECs
1999	FCC 32/	98-45 (Ex Parte)	All LECs
2000	EPA 35/	CAA-00-6	Tennessee Valley Authority
2003	FERC 48/	RM02-7	All Utilities
2003	FCC 52/	03-173	All LECs
2003	FERC	ER03-409-000, ER03-666-000	Pacific Gas and Electric Co.
State Regulatory Agencies			
1982	Massachusetts 17/	DPU 557/558	Western Mass Elec. Co.
1982	Illinois 16/	ICC81-8115	Illinois Bell Telephone Co.
1983	Maryland 8/	7574-Direct	Baltimore Gas & Electric Co.
1983	Maryland 8/	7574-Surrebuttal	Baltimore Gas & Electric Co.
1983	Connecticut 15/	810911	Woodlake Water Co.
1983	New Jersey 1/	815-458	New Jersey Bell Tel. Co.
1983	New Jersey 14/	8011-827	Atlantic City Sewerage Co.
1984	Dist. Of Columbia 7/	785	Potomac Electric Power Co.
1984	Maryland 8/	7689	Washington Gas Light Co.
1984	Dist. Of Columbia 7/	798	C&P Tel. Co.
1984	Pennsylvania 13/	R-832316	Bell Telephone Co. of PA
1984	New Mexico 12/	1032	Mt. States Tel. & Telegraph
1984	Idaho 18/	U-1000-70	Mt. States Tel. & Telegraph
1984	Colorado 11/	1655	Mt. States Tel. & Telegraph
1984	Dist. Of Columbia 7/	813	Potomac Electric Power Co.
1984	Pennsylvania 3/	R842621-R842625	Western Pa. Water Co.
1985	Maryland 8/	7743	Potomac Electric Power Co.
1985	New Jersey 1/	848-856	New Jersey Bell Tel. Co.
1985	Maryland 8/	7851	C&P Tel. Co.
1985	California 10/	I-85-03-78	Pacific Bell Telephone Co.
1985	Pennsylvania 3/	R-850174	Phila. Suburban Water Co.
1985	Pennsylvania 3/	R850178	Pennsylvania Gas & Water Co.
1985	Pennsylvania 3/	R-850299	General Tel. Co. of PA
1986	Maryland 8/	7899	Delmarva Power & Light Co.
1986	Maryland 8/	7754	Chesapeake Utilities Corp.

Michael J. Majoros, Jr.

1986	Pennsylvania 3/	R-850268	York Water Co.
1986	Maryland 8/	7953	Southern Md. Electric Corp.
1986	Idaho 9/	U-1002-59	General Tel. Of the Northwest
1986	Maryland 8/	7973	Baltimore Gas & Electric Co.
1987	Pennsylvania 3/	R-860350	Dauphin Cons. Water Supply
1987	Pennsylvania 3/	C-860923	Bell Telephone Co. of PA
1987	Iowa 6/	DPU-86-2	Northwestern Bell Tel. Co.
1987	Dist. Of Columbia 7/	842	Washington Gas Light Co.
1988	Florida 4/	880069-TL	Southern Bell Telephone
1988	Iowa 6/	RPU-87-3	Iowa Public Service Company
1988	Iowa 6/	RPU-87-6	Northwestern Bell Tel. Co.
1988	Dist. Of Columbia 7/	869	Potomac Electric Power Co.
1989	Iowa 6/	RPU-88-6	Northwestern Bell Tel. Co.
1990	New Jersey 1/	1487-88	Morris City Transfer Station
1990	New Jersey 5/	WR 88-80967	Toms River Water Company
1990	Florida 4/	890256-TL	Southern Bell Company
1990	New Jersey 1/	ER89110912J	Jersey Central Power & Light
1990	New Jersey 1/	WR90050497J	Elizabethtown Water Co.
1991	Pennsylvania 3/	P900465	United Tel. Co. of Pa.
1991	West Virginia 2/	90-564-T-D	C&P Telephone Co.
1991	New Jersey 1/	90080792J	Hackensack Water Co.
1991	New Jersey 1/	WR90080884J	Middlesex Water Co.
1991	Pennsylvania 3/	R-911892	Phil. Suburban Water Co.
1991	Kansas 20/	176, 716-U	Kansas Power & Light Co.
1991	Indiana 29/	39017	Indiana Bell Telephone
1991	Nevada 21/	91-5054	Central Tele. Co. – Nevada
1992	New Jersey 1/	EE91081428	Public Service Electric & Gas
1992	Maryland 8/	8462	C&P Telephone Co.
1992	West Virginia 2/	91-1037-E-D	Appalachian Power Co.
1993	Maryland 8/	8464	Potomac Electric Power Co.
1993	South Carolina 22/	92-227-C	Southern Bell Telephone
1993	Maryland 8/	8485	Baltimore Gas & Electric Co.
1993	Georgia 23/	4451-U	Atlanta Gas Light Co.
1993	New Jersey 1/	GR93040114	New Jersey Natural Gas. Co.
1994	Iowa 6/	RPU-93-9	U.S. West – Iowa
1994	Iowa 6/	RPU-94-3	Midwest Gas
1995	Delaware 24/	94-149	Wilm. Suburban Water Corp.
1995	Connecticut 25/	94-10-03	So. New England Telephone
1995	Connecticut 25/	95-03-01	So. New England Telephone
1995	Pennsylvania 3/	R-00953300	Citizens Utilities Company
1995	Georgia 23/	5503-0	Southern Bell
1996	Maryland 8/	8715	Bell Atlantic
1996	Arizona 26/	E-1032-95-417	Citizens Utilities Company
1996	New Hampshire 27/	DE 96-252	New England Telephone
1997	Iowa 6/	DPU-96-1	U S West – Iowa

Michael J. Majoros, Jr.

1997	Ohio 28/	96-922-TP-UNC	Ameritech – Ohio
1997	Michigan 28/	U-11280	Ameritech – Michigan
1997	Michigan 28/	U-112 81	GTE North
1997	Wyoming 27/	7000-ztr-96-323	US West – Wyoming
1997	Iowa 6/	RPU-96-9	US West – Iowa
1997	Illinois 28/	96-0486-0569	Ameritech – Illinois
1997	Indiana 28/	40611	Ameritech – Indiana
1997	Indiana 27/	40734	GTE North
1997	Utah 27/	97-049-08	US West – Utah
1997	Georgia 28/	7061-U	BellSouth – Georgia
1997	Connecticut 25/	96-04-07	So. New England Telephone
1998	Florida 28/	960833-TP et. al.	BellSouth – Florida
1998	Illinois 27/	97-0355	GTE North/South
1998	Michigan 33/	U-11726	Detroit Edison
1999	Maryland 8/	8794	Baltimore Gas & Electric Co.
1999	Maryland 8/	8795	Delmarva Power & Light Co.
1999	Maryland 8/	8797	Potomac Edison Company
1999	West Virginia 2/	98-0452-E-GI	Electric Restructuring
1999	Delaware 24/	98-98	United Water Company
1999	Pennsylvania 3/	R-00994638	Pennsylvania American Water
1999	West Virginia 2/	98-0985-W-D	West Virginia American Water
1999	Michigan 33/	U-11495	Detroit Edison
2000	Delaware 24/	99-466	Tidewater Utilities
2000	New Mexico 34/	3008	US WEST Communications, Inc.
2000	Florida 28/	990649-TP	BellSouth -Florida
2000	New Jersey 1/	WR30174	Consumer New Jersey Water
2000	Pennsylvania 3/	R-00994868	Philadelphia Suburban Water
2000	Pennsylvania 3/	R-0005212	Pennsylvania American Sewerage
2000	Connecticut 25/	00-07-17	Southern New England Telephone
2001	Kentucky 36/	2000-373	Jackson Energy Cooperative
2001	Kansas 38/39/40/	01-WSRE-436-RTS	Western Resources
2001	South Carolina 22/	2001-93-E	Carolina Power & Light Co.
2001	North Dakota 37/	PU-400-00-521	Northern States Power/Xcel Energy
2001	Indiana 29/41/	41746	Northern Indiana Power Company
2001	New Jersey 1/	GR01050328	Public Service Electric and Gas
2001	Pennsylvania 3/	R-00016236	York Water Company
2001	Pennsylvania 3/	R-00016339	Pennsylvania America Water
2001	Pennsylvania 3/	R-00016356	Wellsboro Electric Coop.
2001	Florida 4/	010949-EL	Gulf Power Company
2001	Hawaii 42/	00-309	The Gas Company
2002	Pennsylvania 3/	R-00016750	Philadelphia Suburban
2002	Nevada 43/	01-10001 &10002	Nevada Power Company
2002	Kentucky 36/	2001-244	Fleming Mason Electric Coop.
2002	Nevada 43/	01-11031	Sierra Pacific Power Company
2002	Georgia 27/	14361-U	BellSouth-Georgia

Michael J. Majoros, Jr.

2002	Alaska 44/	U-01-34,82-87,66	Alaska Communications Systems
2002	Wisconsin 45/	2055-TR-102	CenturyTel
2002	Wisconsin 45/	5846-TR-102	TelUSA
2002	Vermont 46/	6596	Citizen's Energy Services
2002	North Dakota 37/	PU-399-02-183	Montana Dakota Utilities
2002	Kansas 38/	02-MDWG-922-RTS	Midwest Energy
2002	Kentucky 36/	2002-00145	Columbia Gas
2002	Oklahoma 47/	200200166	Reliant Energy ARKLA
2002	New Jersey 1/	GR02040245	Elizabethtown Gas Company
2003	New Jersey 1/	ER02050303	Public Service Electric and Gas Co.
2003	Hawaii 42/	01-0255	Young Brothers Tug & Barge
2003	New Jersey 1/	ER02080506	Jersey Central Power & Light
2003	New Jersey 1/	ER02100724	Rockland Electric Co.
2003	Pennsylvania 3/	R-00027975	The York Water Co.
2003	Pennsylvania /3	R-00038304	Pennsylvania-American Water Co.
2003	Kansas 20/ 40/	03-KGSG-602-RTS	Kansas Gas Service
2003	Nova Scotia, CN 49/	EMO NSPI	Nova Scotia Power, Inc.
2003	Kentucky 36/	2003-00252	Union Light Heat & Power
2003	Alaska 44/	U-96-89	ACS Communications, Inc.
2003	Indiana 29/	42359	PSI Energy, Inc.
2003	Kansas 20/ 40/	03-ATMG-1036-RTS	Atmos Energy
2003	Florida 50/	030001-E1	Tampa Electric Company
2003	Maryland 51/	8960	Washington Gas Light
2003	Hawaii 42/	02-0391	Hawaiian Electric Company
2003	Illinois 28/	02-0864	SBC Illinois
2003	Indiana 28/	42393	SBC Indiana
2004	New Jersey 1/	ER03020110	Atlantic City Electric Co.
2004	Arizona 26/	E-01345A-03-0437	Arizona Public Service Company
2004	Michigan 27/	U-13531	SBC Michigan
2004	New Jersey 1/	GR03080683	South Jersey Gas Company

Michael J. Majoros, Jr.

PARTICIPATION AS NEGOTIATOR IN FCC TELEPHONE DEPRECIATION RATE REPRESCRIPTION CONFERENCES

COMPANY	YEARS	CLIENT
Diamond State Telephone Co. 24/	1985 + 1988	Delaware Public Service Comm
Bell Telephone of Pennsylvania 3/	1986 + 1989	PA Consumer Advocate
Chesapeake & Potomac Telephone Co. - Md. 8/	1986	Maryland People's Counsel
Southwestern Bell Telephone – Kansas 20/	1986	Kansas Corp. Commission
Southern Bell – Florida 4/	1986	Florida Consumer Advocate
Chesapeake & Potomac Telephone Co.-W.Va. 2/	1987 + 1990	West VA Consumer Advocate
New Jersey Bell Telephone Co. 1/	1985 + 1988	New Jersey Rate Counsel
Southern Bell - South Carolina 22/	1986 + 1989 + 1992	S. Carolina Consumer Advocate
GTE-North – Pennsylvania 3/	1989	PA Consumer Advocate

Michael J. Majoros, Jr.

PARTICIPATION IN PROCEEDINGS WHICH WERE SETTLED BEFORE TESTIMONY WAS SUBMITTED

STATE	DOCKET NO.	UTILITY
Maryland 8/	7878	Potomac Edison
Nevada 21/	88-728	Southwest Gas
New Jersey 1/	WR90090950J	New Jersey American Water
New Jersey 1/	WR900050497J	Elizabethtown Water
New Jersey 1/	WR91091483	Garden State Water
West Virginia 2/	91-1037-E	Appalachian Power Co.
Nevada 21/	92-7002	Central Telephone - Nevada
Pennsylvania 3/	R-00932873	Blue Mountain Water
West Virginia2/	93-1165-E-D	Potomac Edison
West Virginia2/	94-0013-E-D	Monongahela Power
New Jersey 1/	WR94030059	New Jersey American Water
New Jersey 1/	WR95080346	Elizabethtown Water
New Jersey 1/	WR95050219	Toms River Water Co.
Maryland 8/	8796	Potomac Electric Power Co.
South Carolina 22/	1999-077-E	Carolina Power & Light Co.
South Carolina 22/	1999-072-E	Carolina Power & Light Co.
Kentucky 36/	2001-104 & 141	Kentucky Utilities, Louisville Gas and Electric
Kentucky 36/	2002-485	Jackson Purchase Energy Corporation

Michael J. Majoros, Jr.

Clients

1/ New Jersey Rate Counsel/Advocate	33/ Michigan Attorney General
2/ West Virginia Consumer Advocate	34/ New Mexico Attorney General
3/ Pennsylvania OCA	35/ Environmental Protection Agency Enforcement Staff
4/ Florida Office of Public Advocate	36/ Kentucky Attorney General
5/ Toms River Fire Commissioner's	37/ North Dakota Public Service Commission
6/ Iowa Office of Consumer Advocate	38/ Kansas Industrial Group
7/ D.C. People's Counsel	39/ City of Witchita
8/ Maryland's People's Counsel	40/ Kansas Citizens' Utility Rate Board
9/ Idaho Public Service Commission	41/ NIPSCO Industrial Group
10/ Western Burglar and Fire Alarm	42/ Hawaii Division of Consumer Advocacy
11/ U.S. Dept. of Defense	43/ Nevada Bureau of Consumer Protection
12/ N.M. State Corporation Comm.	44/ GCI
13/ City of Philadelphia	45/ Wisc. Citizens' Utility Rate Board
14/ Resorts International	46/ Vermont Department of Public Service
15/ Woodlake Condominium Association	47/ Oklahoma Corporation Commission
16/ Illinois Attorney General	48/ National Association of Utility Consumer Advocates
17/ Mass Coalition of Municipalities	49/ Nova Scotia Utility and Review Board
18/ U.S. Department of Energy	50/ Florida Office of Public Counsel
19/ Arizona Electric Power Corp.	51/ Maryland Public Service Commission
20/ Kansas Corporation Commission	52/ MCI
21/ Public Service Comm. – Nevada	53/ Transmission Agency of Northern California
22/ SC Dept. of Consumer Affairs	
23/ Georgia Public Service Comm.	
24/ Delaware Public Service Comm.	
25/ Conn. Ofc. Of Consumer Counsel	
26/ Arizona Corp. Commission	
27/ AT&T	
28/ AT&T/MCI	
29/ IN Office of Utility Consumer Counselor	
30/ Unitel (AT&T – Canada)	
31/ Public Interest Advocacy Centre	
32/ U.S. General Services Administration	

Exhibit___(MJM-4)

STATE COOLING DEGREE DAYS (DIVISIONS WEIGHTED BY 2000 POPULATION), THRU OCT   2003--BASE TEMP = 65 DEG F

STATE : 11 ILLINOIS

YEAR	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC
2002	0	0	0	2	26	233	383	286	134	1	0	0
2002	0	0	0	2	28	261	644	930	1064	1065	1065	1065
2002	.0	.0	.0	52.6	39.5	100.2	116.5	117.3	121.2	119.1	119.1	119.1
2003	0	0	1	2	40	113	263	301	59	8	0	0
2003	0	0	1	3	43	156	419	720	779	787	0	0
2003	.0	.0	71.4	78.9	60.7	59.9	75.8	90.8	88.7	88.0	.0	.0

STATE : 12 INDIANA

YEAR	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC
2002	0	0	0	3	34	245	371	304	160	5	0	0
2002	0	0	0	3	37	282	653	957	1117	1122	1122	1122
2002	.0	.0	.0	73.2	49.8	106.7	118.5	122.6	127.4	125.8	125.8	125.8
2003	0	0	1	2	53	118	253	282	61	5	0	0
2003	0	0	1	3	56	174	427	709	770	775	0	0
2003	.0	.0	50.0	73.2	75.4	65.8	77.5	90.8	87.8	86.9	.0	.0

STATE : 13 IOWA

YEAR	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC
2002	0	0	0	0	28	236	362	216	100	0	0	0
2002	0	0	0	0	28	264	626	842	942	942	942	942
2002	.0	.0	.0	.0	38.0	100.8	112.0	106.8	110.2	108.6	108.6	108.6
2003	0	0	0	1	35	127	262	301	40	7	0	0
2003	0	0	0	1	36	163	425	726	766	773	0	0
2003	.0	.0	.0	24.4	48.8	62.2	76.0	92.1	89.6	89.1	.0	.0

STATE : 14 KANSAS

YEAR	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC
2002	0	0	0	17	64	348	494	437	237	1	0	0
2002	0	0	0	17	81	429	923	1360	1597	1598	1598	1598
2002	.0	.0	.0	67.2	61.2	101.3	104.4	106.0	109.6	107.2	107.2	107.2
2003	0	0	2	16	84	204	525	501	110	24	0	0
2003	0	0	2	18	102	306	831	1332	1442	1466	0	0
2003	.0	.0	28.6	71.1	77.1	72.2	94.0	103.8	98.9	98.4	.0	.0

STATE : 15 KENTUCKY

YEAR	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC
2002	0	0	4	21	66	293	425	398	235	21	0	0
2002	0	0	4	25	91	384	809	1207	1442	1463	1463	1463
2002	.0	.0	36.4	116.8	79.2	111.2	117.6	121.5	125.8	124.7	124.6	124.6
2003	0	0	11	17	93	148	326	347	110	18	0	0
2003	0	0	11	28	121	269	595	942	1052	1070	0	0
2003	.0	.0	100.0	130.8	105.3	77.9	86.5	94.8	91.8	91.2	.0	.0

LINE 1 = COOLING DEGREE DAYS (DIVISIONS WEIGHTED BY 2000 POPULATION)
LINE 2 = ACCUMULATED COOLING DEGREE DAYS(DIVISIONS WEIGHTED BY 2000 POPULATION)
LINE 3 = [ACCUMULATED COOLING DEGREE DAYS (DIVISIONS WEIGHTED BY 2000 POPULATION) / ACCUMULATED NORMAL]*100
PERCENTAGE OF 9999.9 => 10000

COMMONWEALTH OF KENTUCKY

RECEIVED

MAR 2 3 2004

PUBLIC SERVICE COMMISSION

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

AN ADJUSTMENT OF THE GAS AND ELECTRIC RATES, TERMS AND CONDITIONS OF LOUISVILLE GAS AND ELECTRIC COMPANY	))))	CASE NO. 2003-00433
AN ADJUSTMENT OF THE ELECTRIC RATES, TERMS AND CONDITIONS OF KENTUCKY UTILITIES COMPANY	))))	CASE NO. 2003-00434

DIRECT TESTIMONY

AND EXHIBITS

OF

MICHAEL J. MAJOROS, JR.

(SFAS NO. 143)

On Behalf of the Office Of Rate Intervention Of The Attorney General Of The Commonwealth Of Kentucky

March 23, 2004

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME, POSITION AND BUSINESS ADDRESS.

A. My name is Michael J. Majoros, Jr. I am Vice President of Snavely King Majoros O'Connor & Lee, Inc. ("Snavely King"). My business address is 1220 L Street, N.W., Suite 410, Washington, D.C. 20005.

Q. PLEASE DESCRIBE SNAVELY KING.

A. Snavely King is an economic consulting firm founded in 1970 to conduct research on a consulting basis into the rates, revenues, costs and economic performance of regulated industries and firms. The firm has a professional staff of 15 economists, accountants, engineers and cost analysts. Much of its work involves the development, preparation and presentation of expert witness testimony before federal and state regulatory agencies. Over the course of its 33-year history, members of the firm have participated in over 1,000 proceedings before almost all of the state and all federal Commissions that regulate utilities or transportation industries.

Q. HAVE YOU ATTACHED A SUMMARY OF YOUR QUALIFICATIONS AND EXPERIENCE?

A. Yes, Appendix A contains a summary of my qualifications and experience. It also includes a listing of my appearances before regulatory bodies.

Q. FOR WHOM ARE YOU APPEARING IN THIS PROCEEDING?

A. I am appearing on behalf of the Attorney General of the Commonwealth of Kentucky ("the AG").

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The purpose of this testimony is to present the AG's position on the Companies' SFAS No. 143 adjustments. I am responsible for the AG's depreciation positions in both the KU and LGE cases. Due to the similarity of the issues between the Companies and the overall magnitude of the analyses and calculations, I filed one common piece of depreciation-related testimony on behalf of the AG.

Since, the Companies' SFAS No. 143 adjustments also relate to depreciation, I had originally intended to include the SFAS No. 143 testimony in the depreciation testimony.[1] However, due to the complexity of the combined issues (depreciation and SFAS No. 143), I concluded that it would be feasible and more understandable to separate them into two discrete pieces of testimony. I am, therefore, filing this common testimony addressing the Companies' SFAS No. 143 adjustments.

II. SUMMARY AND CONCLUSIONS

Q. PLEASE SUMMARIZE YOUR FINDINGS AND CONCLUSIONS.

A. Ms. Scott sponsors the both Companies SFAS No. 143 adjustments. The adjustments increase KU's revenue requirement by $8.5 million and LGE's by $5.3 million. This accounting change should not result in a revenue requirement increase; in fact, if anything it should result in a major revenue requirement reduction. These Companies have collectively charged ratepayers more than $456 million on a combined basis, which SFAS No. 143 now highlights as a liability (amount owed) to ratepayers. In my opinion, Ms. Scott's adjustments are

[1] SFAS No. 143 also has significant accounting implications.

unnecessary, unjustified and unreasonable. Consequently, I recommend that Ms. Scott's SFAS No. 143 adjustments be disallowed.

III. FINANCIAL ACCOUNTING STANDARDS BOARD'S STATEMENT OF FINANCIAL ACCOUNTING STANDARDS NO. 143

Q. WHAT IS THE NATURE OF MS. SCOTT'S SFAS NO. 143 ADJUSTMENTS?

A. Ms. Scott sponsors the Companies implementation of the Financial Accounting Standards Board's ("FASB") Statement of Financial Accounting Standards No. 143 ("SFAS No. 143.") This new accounting standard and its FERC USOA counterpart, Order No. 631, deal with the cost of removal aspects of depreciation.

Q. WHAT IS THE FINANCIAL ACCOUNTING STANDARDS BOARD?

A. The Financial Accounting Standards Board ("FASB") is a standards-setting body for the public accounting profession.

Q. WHAT IS SFAS NO. 143?

A. SFAS No. 143 - Accounting for Asset Retirement Obligations, is a recent FASB pronouncement concerning the appropriate accounting for asset retirement costs that meet the definition of a liability.

Q. WHAT IS THE GENESES OF SFAS NO. 143?

A. SFAS No. 143 was initiated in 1994 as a result of a request by the Edison Electric Institute. Subsequent to that initiation, the accounting community went through several iterations of proposals and comments to finally arrive at SFAS No. 143.

Q. PLEASE EXPLAIN SFAS NO. 143.

A. Pursuant to SFAS No. 143 all companies (including KU and LGE) must review all of their long-lived assets to determine whether or not they have actual legal obligations to remove those assets upon retirement. For some plant and equipment, public utilities have a legal obligation to remove the asset at the end of its service life. These legal obligations for future removal are considered to meet the definition of a liability and are called asset retirement obligations ("AROs").

Q. HOW ARE AROs TREATED ON A COMPANY'S BOOKS?

A. AROs are considered to be a component of the original cost of an asset, because incurring a liability is essentially the same as paying cash for an asset. In both instances a cost is incurred. For other assets, where no such obligation exists, any incidental retirement cost is not treated as part of the original cost of the asset, rather it is charged to an expense.

Q. HOW ARE AROs MEASURED?

A. If a Company does have an ARO liability, it is measured at its "fair value." A present value approach is typically used to measure the fair value of the liability. In summary, estimates of the future inflated cost of the ARO are made, but then they are discounted back to their net present value in order to be capitalized as a liability and included in the original cost of an asset. Since the net present value of the future retirement cost is capitalized as a component of the original cost of the asset, it is depreciated over the life of the asset.

Q. PLEASE SUMMARIZE DEPRECIATION ACCOUNTING?

A. Each year a portion of the original cost is charged to depreciation expense and is also recorded in the accumulated depreciation account. The accumulated depreciation account is cumulative over the life of the asset. At any point in time, the accumulated depreciation account shows the cumulative depreciation expense to date. Hence, for assets with AROs, the accumulated depreciation account would equal the original cost plant balance (which includes the net present value of the ARO) at the end of the asset's life.

Q. DOES THE LIABILITY THAT IS ESTABLISHED WHEN THE ARO IS CAPITALIZED REMAIN THE SAME EACH YEAR?

A. No. Each year, as the liability increases due to inflation, the increase is charged to accretion expense and credited to the liability. This credit increases the liability but the asset value remains the same. In other words, just as the original cost of the asset does not increase, neither does the capitalized asset retirement cost.

Q. WHAT IF A COMPANY DOES NOT HAVE A LEGAL ARO?

A. If a Company does not have such legal obligations, no future cost of removal is capitalized. Since the cost is not capitalized, it is not included in depreciation expense. Again, even for assets without AROs, at the end of their life, the accumulated depreciation account will equal the plant balance because only the original cost of the asset will have been depreciated.[2] In other words, there is symmetry between assets with and without AROs. In both cases, the accumulated depreciation will equal the original cost of the asset at the end of its life.

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[2] In this case, the original cost is the amount paid, but <u>no</u> ARO.

IV. PREVIOUS UTILITY ACCOUNTING

Q. IS AN ARO THE SAME AS FUTURE COST OF REMOVAL?

A. An ARO results in an Asset Retirement Cost ("ARC") which is the fair value (net present value) of the estimated future cost of removal.

Q. HOW HAVE UTILITIES TYPICALLY ACCOUNTED FOR FUTURE COST OF REMOVAL?

A. Typically, utilities have incorporated inflated cost of removal estimates in their depreciation rates. These estimates have increased the depreciation rates.

Q. WHAT IS THE ACCOUNTING RESULT OF THIS TYPICAL UTILITY PRACTICE?

A. Accumulated depreciation exceeds the original cost of the asset at the end of its life. That is because the depreciation rate is set to recover substantially more depreciation than the original cost of the asset. Remember, the rates were set to recover <u>inflated</u> cost of removal estimates. This is an anomaly, i.e., excessive accumulated depreciation, that SFAS No. 143 intentionally sought to cure.

Q. HOW DOES SFAS NO. 143 CURE THIS ANOMALY?

A. SFAS No. 143 cures the anomaly by unbundling net salvage from depreciation rates. It does this in one of two ways. The first way is to incorporate the net present value of a legal ARO in the original cost of the asset. This is a cure because at the end of the asset's life, the original cost and accumulated depreciation equal one another. The second cure is to eliminate future net salvage from depreciation rate calculations for assets without legal AROs.

Again, the original cost of the asset and accumulated depreciation will match one another at the end of life.

Q. WITH RESPECT TO NON-AROs, WHAT HAPPENS IF A COMPANY INCURS INCIDENTAL REMOVAL COST AT THE END OF THE ASSET'S LIFE?

A. Any incidental costs will be expensed, or perhaps treated as a component of a replacement asset.

Q. WHAT IS THE FINANCIAL ACCOUNTING IMPACT OF SFAS NO. 143 FOR ELECTRIC UTILITIES?

A. Electric utilities are required to review all of their assets to determine if they have any AROs. If they do, they are required to use the capitalization and depreciation accounting described above, and they must also make a "transition adjustment" which I will discuss later in this testimony.

Q. WHAT IF UTILITIES HAVE AROs FOR SOME ASSETS, BUT NOT ALL ASSETS?

A. In addition to the depreciation, capitalization and transition accounting, they are also required to determine the amount of any prior cost of removal collections relating to <u>non-AROs</u> that is now included in their accumulated depreciation accounts. In other words, the amounts relating to the inflated cost of removal estimates that were previously incorporated in depreciation rate calculations. These latter amounts and any such future charges to ratepayers (for non-AROs) are to be recorded as a regulatory liability to ratepayers.[3]

V. <u>FERC ORDER NO. 631</u>

[3] SFAS No. 143, paragraph *B73*.

Q. WHAT IS THE REGULATORY ACCOUNTING IMPACT OF SFAS NO. 143 ON ELECTRIC UTILITIES?

A. The impact on regulatory accounting for electric utilities is that SFAS No. 143 evolved into Order No. 631 in FERC Docket RM02-7-000. FERC Order No. 631 resulted in changes to the USOA to incorporate the principles of SFAS No. 143.

Q. HOW DID SFAS NO. 143 EVOLVE INTO FERC ORDER NO. 631?

A. FERC established Docket No. RM02-7-000 as a result of the FASB's adoption of SFAS No. 143. This docket has included a Technical Conference, Comments, a Notice of Proposed Rulemaking ("NOPR"), Additional Comments and ultimately, Order No. 631, on April 9, 2003.

Q. DO YOU HAVE ANY FAMILIARITY WITH FERC ORDER NO. 631?

A. Yes, I have followed the progress of SFAS No. 143 into FERC Docket No. RM02-7. I also attended the FERC's Technical conference, and submitted Comments on behalf of the National Association of Utility Consumer Advocates. Exhibit___(MJM-I) is a document I wrote tracking the progress of SFAS No. 143 into FERC Order No. 631. It primarily addresses net salvage as it relates to non-ARO assets, since that is one of the subjects in dispute.

Q. WHAT IS THE THRUST OF ORDER NO. 631?

A. Order No. 631 essentially adopts SFAS No. 143 and then integrates it into the Uniform System of Accounts.

Q. ARE LGE AND KU AWARE OF FERC ORDER NO. 631?

A. Yes.

Q. HAVE THESE COMPANIES IMPLEMENTED SFAS NO. 143 AND FERC ORDER 631?

A. Yes. These Companies implemented both, effective January 1, 2003.

Q. DO THE COMPANIES HAVE ANY ASSET RETIREMENT OBLIGATIONS PURSUANT TO SFAS NO. 143?

A. Yes. Upon review, the Companies found that they do have certain legal AROs.

VI. PRIOR SETTLEMENTS

Q. HAVE THE COMPANIES RECORDED ANY IMPACTS RELATED TO SFAS NO. 143 ON THEIR BOOKS?

A. It appears that the Companies have recorded certain amounts on their books as a result of settlement agreements in Case Nos. 2003-00426 and 2003-00427.

Q. DID THE COMMISSION APPROVE THAT SETTLEMENT?

A. Yes, but only for accounting purposes. In its December 23, 2003, Order the Commission noted that SFAS NO. 143 was to become effective as of January 1, 2003 and that the FERC had issued its final rule (FERC Order No. 631) on April 9, 2003.[4]

Among other things, the Commission noted that the Companies requested Commission approval to establish regulatory asset and liability accounts associated with the adoption of SFAS No. 143. The Commission went on to note that "based on the assumption that the cost of removal was covered by the Commission's previous approval of the depreciation rates currently in effect," the Companies did not previously seek approval to establish the regulatory asset and

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[4] Case Nos. 2003-00426 and 2003-00427, Order dated December 23, 2003 ("Dec.23 Order"), page 1-2.

liability accounts. However, the Companies stated that if the Commission did not agree with the assumption, the Companies also requested approval of the regulatory asset and liability accounts in this proceeding.[5]

Specifically, the parties to the stipulation requested the Commission to issue an Order which:

1) Approves the regulatory assets and liabilities associated with adopting SFAS No. 143 and going forward;

2) Eliminates the impact on net operating income in the 2003 ESM annual filing caused by adopting SFAS No. 143;

3) To the extent accumulated depreciation related to the cost of removal is recorded in regulatory assets or regulatory liabilities, such amounts will be reclassified to accumulated depreciation for rate-making purposes of calculating rate base; and

4) The ARO assets, related ARO asset accumulated depreciation, ARO liabilities, and remaining regulatory assets associated with the adoption of SFAS No. 143 will be excluded from rate base.[6]

Q. WHAT WAS THE COMMISSION'S RESPONSE?

A. The Commission approved the establishment of the regulatory asset and liability accounts, but cautioned that "this approval is for accounting purposes only and the appropriate rate-making treatment for these regulatory assets and liability accounts will be addressed in the Companies' next general rate case."[7] The Commission stated that it "is not clear as to the exact meaning of Nos. 3 and 4 [see above] of the Stipulation," and that "based upon [its] understanding of the provisions of the Stipulation, the Commission finds that Nos. 3 and 4 should be

[5] Id., page 3, footnote 4.
[6] Id., page 3
[7] Id., page 4

approved for the purposes of the calendar year 2003 ESM calculations only. Consistent with [its] approval of the regulatory asset and liability accounts, the Commission will address the rate-making treatment for base rates in the next general rate case."[8]

VII. ACCOUNTING ENTRIES

Q. HAVE YOU REVIEWED THE COMPANIES' ACCOUNTING ENTRIES ASSOCIATED WITH THEIR IMPLEMENTATION OF SFAS NO. 143?

A. Yes. The Companies provided these entries in response to Staff data requests. Exhibit___(MJM-2) contains selected pages from the response to the Staff data request, No. 56(c) in Docket 2003-00434.[9] The specific journal entries are identified at pages 17 to 22 of 441 pages of the original response.

Q. DO YOU AGREE WITH THESE ENTRIES?

A. Not entirely. First, the final entry, i.e., the debit to account 182.3 with a corresponding credit to account 407, appears to have been contrived to create an incremental revenue requirement which Ms. Scott then proposes in this case. Second, they are incomplete.

VIII. MS. SCOTT'S ADJUSTMENTS

Q. WHY DO YOU SAY THAT THE DEBITS TO ACCOUNT 182.3 AND THE CORRESPONDING CREDIT APPEAR TO HAVE BEEN CONTRIVED TO CREATE AN INCREMENTAL REVENUE REQUIREMENT?

A. Because they do create an incremental revenue requirement for each Company, as shown in Ms. Scott's testimony and adjustment. These in turn, resulted from

[8] Id., pages 4-5.

[9] The Companies supplied the same information in each Docket.

an unnecessary charge to below-the line net income, which the Companies then requested to have neutralized by an above-the line entry creating an incremental requirement.

Q. PLEASE EXPLAIN MS. SCOTT'S ADJUSTMENTS IN THE CURRENT CASES?

A. Ms. Scott's adjustments are the result of the cumulative effect adjustment the Companies booked as a result of the Commission's decision in the aforementioned stipulation. A cumulative effect adjustment is a catch-up or "transition" accounting entry to implement SFAS No.143. The Executive Summary included in the Companies' response to PSC Question No. 56(c) indicates that the cumulative effect was supposed to be revenue neutral.[10] However, based on Ms. Scott's testimony and adjustments, it is not revenue neutral, it creates additional revenue requirements.

Q. DO THE TERMS OF THE STIPULATION AND/OR THE COMMISSION'S DECISION REQUIRE THAT ALL PARTIES ACCEPT THAT RESULT IN THIS PROCEEDING?

A. No. The Commission stated that it was not clear as to the meaning of certain aspects of that stipulation and that the resulting Order was only an Accounting Order which did not control ratemaking.

Q. WHAT IS THE REVENUE REQUIREMENT IMPACT OF THE COMPANIES' IMPLEMENTATION OF SFAS NO. 143?

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[10] See Exhibit___(MJM-2), page 3 of 441.

A. According to Ms. Scott's testimony and exhibits, the revenue requirement impact is $8.5 for KU and $5.3 for LGE.

Q. ARE THERE ANY OFFSETTING ABOVE-THE-LINE CREDITS THAT REDUCE THESE AMOUNTS TO REVENUE NEUTRALITY IN THE RATE CASES?

A. I have not found any above-the-line credits that reduce these incremental revenue requirements to revenue neutrality.

Q. DO YOU OBJECT TO THE TREATMENT DESCRIBED ABOVE?

A. Yes. It is my opinion that the accounting described above, which results in incremental revenue requirements, is inconsistent with the principles of the regulatory accounting required by FERC Order No. 631.

Q. WHY DO YOU BELIEVE THAT MS. SCOTT'S PROPOSED ADJUSTMENTS ARE INCONSISTENT WITH THE PRINCIPLES OF ORDER NO. 631?

A. I do not believe that the FERC intended for the implementation of Order No. 631 to result in incremental revenue requirements where Companies have legal AROs. Far more likely is the possibility of revenue requirement reductions when Companies that have been collecting cost of removal in depreciation rates but now determine that they do not have equivalent legal AROs.

Q. CAN YOU PROVIDE AN EXAMPLE?

A. Yes. Based on my background and experience, I am well aware that most electric and gas utilities have, for a long period of time, been collecting in their depreciation rates, substantial amounts from ratepayers for future cost of removal. These amounts currently reside in these Companies' accumulated depreciation accounts.

I assume that the FERC was also aware of these facts when in began its Docket No. RM02-7, which ultimately resulted in its Order No. 631. The FERC issued its Notice of Proposed Rulemaking ("NOPR") in Docket No. RM02-7 on October 30, 2002. Section E of the NOPR deals with the "Proposed Accounting for Transition Adjustments." Paragraph 38 of that section of the NOPR states:

> "The Commission [FERC] proposes that when the amount of any previously recognized retirement obligation recorded in account 108 [accumulated depreciation] ... is greater than the amount recognized under the proposed rule, [i.e., company has collected too much] the excess must be credited to account 254, Other Regulatory liabilities. However, when the amount of any previously recognized asset retirement obligation in account 108 [accumulated depreciation] ... is less than the amount recognized under the proposed rule, [i.e., company believes it has not collected enough] the Commission proposes that the difference must be charged to income in account 435, Extraordinary deductions, and the related income taxes recorded in account 409.3, Income taxes, extraordinary items, and reported as a cumulative effect of a change in accounting principle.[11]

This means that the FERC initially proposed to treat any prior over-recovery of depreciation on legal AROs as a liability to ratepayers, but charge any prior under-recovery of AROs as calculated by a Company below-the-line. It recognized that such amounts would have to first be approved by a state commission before they could be charged to ratepayers. The initial treatment, however, and the thrust was to return prior over-recoveries to ratepayers and

[11] Order No. 631, paragraph 38.

charge any prior under-recoveries to shareholders. Importantly, these proposed rules related to legal AROs.

Q. WHAT DO YOU RECOMMEND?

A. I recommend that Ms. Scott's proposed incremental revenue requirements for the implementation of SFAS No. 143 be disallowed, unless she can demonstrate an equal offsetting above-the-line adjustment which renders her proposal revenue neutral. As I will demonstrate below, these Companies have already collectively recovered more than $456 million from their ratepayers for future cost of removal that they have no obligation to incur. These amounts are liabilities to ratepayers. There is certainly no reason to increase service rates for any additional asset retirement costs, legal or otherwise, when the Companies have already over-collected to such a great extent.

IX. EXCESSIVE ACCUMULATED DEPRECIATION

Q. WHY ARE THE COMPANIES' ACCOUNTING ENTRIES INCOMPLETE?

A. Refer to page 11 of 441 under the heading "Regulatory Asset and Liabilities." Item 2 states;

> Regulatory Liabilities-Pursuant to SFAS 71 previously accrued removal costs in excess of that allowed under SFAS No. 143 is offset with a regulatory liability. The regulatory liability is established by a credit to account 254, "Regulatory Liabilities".[12]

This statement refers not only to assets which have AROs, but also to assets that do not have AROs.

[12] Response to PSC Question No. 56(c) page 11 of 441, Scott.

Paragraph *B73.* of SFAS No. 143 requires that if the Companies collected cost of removal in the past and recorded it in accumulated depreciation (which these Companies did), but have no liability for those collections, (which these Companies don't), those amounts must also be separated from accumulated depreciation and recorded as a regulatory liability (amount owed) to ratepayers. The Companies' journal entries are incomplete, because they do not include the entries for these regulatory liabilities to ratepayers.

Q. DO YOU THINK IT WAS MISLEADING FOR THE COMPANIES TO ADOPT THIS APPROACH AND NOT REVEAL THESE ENTRIES?

A. Yes. Remember the Commission's stated uncertainty as to the meaning of items 3 and 4 of the stipulation. The Companies provisions 3 and 4 hid the magnitude of these huge regulatory liabilities to ratepayers.

Q. DO THE COMPANIES KNOW THE AMOUNTS OF THESE REGULATORY LIABILITIES?

A. Yes, they collectively exceed $456 million. I will discuss these regulatory liabilities in more detail later in this testimony.

Q. WHAT ARE THE IMPLICATIONS OF ORDER NO. 631 IN SITUATIONS WHERE ELECTRIC UTILITIES DO NOT HAVE AROS?

A. FERC Order No. 631 defines cost of removal allowances for which there is no legal asset retirement obligation, as "non-legal retirement obligations." Past and future "non-legal AROs" must be specifically identified and accounted for separately in the depreciation studies, depreciation expense and the accumulated depreciation account.

In Order No. 631, FERC established new requirements for non-legal AROs, as follows:

> Instead, we will require jurisdictional entities to maintain separate subsidiary records for cost of removal for non-legal retirement obligations that are included as specific identifiable allowances recorded in accumulated depreciation in order to separately identify such information to facilitate external reporting and for regulatory analysis, and rate setting purposes. Therefore, the Commission is amending the instructions of accounts 108 and 110 in Parts 101, 201 and account 31, Accrued depreciation - Carrier property, in Part 352 to require jurisdictional entities to maintain separate subsidiary records for the purpose of identifying the amount of specific allowances collected in rates for non-legal retirement obligations included in the depreciation accruals.[13]

Q. DOES FERC PROVIDE ANY ADDITIONAL INSIGHT AS TO THE INTERPRETATION OF THESE NEW RULES?

A. Yes, FERC also states:

> Jurisdictional entities must identify and quantify in separate subsidiary records the amounts, if any, of previous and current accumulated removal costs for other than legal retirement obligations recorded as part of the depreciation accrual in accounts 108 and 110 for public utilities and licensees, account 108 for natural gas companies, and account 31 for oil pipeline companies. If jurisdictional entities do not have the required records to separately identify such prior accruals for specific identifiable allowances collected in rates for non-legal asset retirement obligations recorded in accumulated depreciation, the Commission will require that

[13] FERC Docket No. RM02-7-000, Order No. 631, Issued April 9, 2003, Paragraph 38.

> the jurisdictional entities separately identify and quantify prospectively the amount of current accruals for specific allowances collected in rates for non-legal retirement obligations."[14]

Q. DOES FERC MAKE ANY POLICY CALLS CONCERNING THE APPROPRIATE TREATMENT OF THE DISPOSITION OF PRIOR AND FUTURE COLLECTIONS CONTAINED IN THESE SEPARATE ALLOWANCES?

A. No. FERC declines to make such calls on a policy basis. FERC will resolve the appropriate treatment of the dispositions of prior and future collections on a case-by-case basis. Specifically, FERC states:

> "The Commission will decline to make policy calls concerning regulatory certainty for disposition of transition costs, external funds for amounts collected in rates for asset retirement obligations, adjustments to book depreciation rates, and the exclusion of accumulated depreciation and accretion for asset retirement obligations from rate base; these are matters that are not subject to a one size fits all approach and are better resolved on a case-by-case basis in rate proceedings. The Commission is of the view that utilities will have the opportunity to seek recovery of qualified costs for asset retirement obligations in individual rate proceedings. <u>This rule should not be construed as pregranted authority for rate recovery in a rate proceeding</u>."[15]

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[14] <u>Id</u>., Paragraph 39.

[15] <u>Id</u>., Paragraph 64. (Emphasis added.)

Q. DOES FERC'S ORDER REQUIRE ANYTHING NEW OR MORE WITH RESPECT TO ITS REQUIREMENT FOR DETAILED DEPRECIATION STUDIES?

A. No. FERC states:

> "Finally this rule requires nothing new and nothing more with respect to the requirement for a detailed study. Complex depreciation and negative salvage studies are routinely filed or otherwise made available for review in rate proceedings. When utilities perform depreciation studies, a certain amount of detail is expected. It is incumbent upon the utility to provide sufficient detail to support depreciation rates, cost of removal, and salvage estimates in rates.45." [16]

And footnote 45 states:

> "When an electric utility files for a change in its jurisdictional rates, the Commission requires detailed studies in support of changes in annual depreciation rates if they are different from those supporting the utility's prior approved jurisdictional rate." [17]

Thus, FERC recognizes distinctions between legal and non-legal AROs just as SFAS No. 143 recognizes those distinctions. In fact, the amount resulting from Order No. 631's requirement to identify previous amounts collected for non-legal AROs should result in the same amounts as the SFAS No. 143 requirement to establish a regulatory liability to ratepayers. It is also clear, that on a going-forward basis, jurisdictional entities must be prepared to specifically identify and justify any non-legal AROs that they propose to include in rates.

[16] Id., paragraph 65.

[17] Id., footnote 45.

Q. DOES ORDER NO. 631 REQUIRE ELECTRIC UTILITIES TO REVIEW THEIR LONG-LIVED ASSETS TO DETERMINE WHETHER THEY HAVE ANY AROs?

A. Yes. Order No. 631 adopts SFAS No. 143, which already obligates electric utilities, among others, to review their long-lived assets to determine if they have any AROs.

Q. IS THE REVIEW REQUIRED BY ORDER NO. 631 THE SAME AS THE REVIEW THAT THESE COMPANIES HAVE ALREADY PERFORMED UNDER SFAS NO. 143?

A. Yes, it is.

Q. WHAT IS THE MOST IMPORTANT ASPECT OF ORDER NO. 631?

A. The most important aspect of Order No. 631 is its requirement to separate or unbundle non-legal cost of removal allowances from depreciation rates.

Q. HOW MUCH PRIOR COLLECTIONS ARE INCLUDED IN THE COMPANIES' ACCUMULATED DEPRECIATION ACCOUNTS?

A. Ms. Scott's response to Staff Q-56(c) in the KU case indicates that as of December 31, 2002, KU had already collected $235.1 million from its Kentucky customers, $13.4 million from its Virginia customers, and LGE had collected $207.9 million from its customers for future cost of removal relating to non-legal AROs.[18] In total, this amounts to $456.4 million of charges to customers for money that these companies have not spent and are under no obligation to spend in the future.

Q. WHO CALCULATED THESE AMOUNTS?

[18] Exhibit __ (MJM-2), pages 44 to 64 of 441.

A. The Companies calculated these amounts.

Q. IS MR. ROBINSON PROPOSING TO INCLUDE ANY ADDITIONAL FUTURE REMOVAL COSTS IN HIS DEPRECIATION RATES?

A. Yes. Mr. Robinson's depreciation rates are designed to collect an additional annual amount of about $25.6 million from LGE for future removal costs and $23.5 million for KU removal costs. This sums to $49 million per year for negative net salvage even though the annual experience of the combined companies is actually only $53 thousand.[19] Mr. Robinson would do this by bundling super-inflated net salvage ratios in his depreciation rates.

Q. WHAT IS YOUR REACTION TO THE COMPANIES' FILINGS?

A. My reaction is that even though these Companies have implemented SFAS No. 143 and apparently Order No. 631, they are proposing to charge much more to their ratepayers for non-legal AROs than they would if it actually had legal obligations to remove these assets.

Q. WHAT IS YOUR OPINION REGARDING THE COMPANIES' SFAS NO. 143 PROPOSALS?

A. The SFAS No. 143 proposals are unreasonable for several reasons. First, they are incomplete; they do not boldly reveal that as a result of the implementation of SFAS No. 143, the Companies have quantified an amount of prior collections (from ratepayers) of so-called future cost of removal which exceeds $456 million, for which the Companies have no obligation or intention to spend. This amount is a Regulatory Liability (amount owed) to ratepayers. The Companies quantified

[19] These figures are described in my depreciation testimony.

these amounts but do not expressly reveal them in their revenue requirement filings. At the same time, the Companies request unnecessary revenue requirement increases under the auspices of their adoption of SFAS No. 143, when they should be recommending decreases. There is no rational reason for SFAS No. 143 to result in a revenue requirement increase when the Companies have acknowledged and quantified a $456 million over-collection from ratepayers.

Q. HOW DO YOU PROPOSE TO DISPOSE OF THE AMOUNTS?

A, First, Ms. Scott's incremental revenue requirements adjustments must be disallowed. Second, Mr. Robinson's incremental cost of removal amounts must be disallowed and replaced with a more reasonable net salvage allowance. This is explained in the depreciation testimony.

Q. HOW ABOUT THE $456 MILLION OVERCOLLECTION?

A. I have left that in the accumulated depreciation account. It will eventually be recognized in ratepayers service rates as very slight reductions to depreciation expense.

Q. ARE THERE ANY ALTERNATIVE APPROACHES?

A. Yes, the excess could be amortized over some period, say 10 years. In those circumstances, Kentucky ratepayers would be getting credits of about $46 million per year.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes, it does.

In the Matter of:

AN ADJUSTMENT OF THE ELECTRIC RATES, TERMS AND CONDITIONS OF KENTUCKY UTILITIES COMPANY	)))	**CASE NO: 2003-00434**

AND

AN ADJUSTMENT OF THE GAS AND ELECTRIC RATES, TERMS AND CONDITIONS OF LOUISVILLE GAS AND ELECTRIC COMPANY	)))	**CASE NO: 2003-00433**

AFFIDAVIT

Comes the affiant, Michael Majoros, Jr., and being duly sworn states that the foregoing testimony and attached schedules were prepared by him or under his direction and supervision and are, to the best of his information and belief, true and correct.

Washington,
District of Columbia

Subscribed and sworn to before me by the Affiant Michael Majoros, Jr. this the 22nd day of March, 2004.

Notary Public, Washington, D.C.
My Commission Expires: 3-14-06

**Summary and Analysis of SFAS No. 143 and FERC Order No. 631
As They Relate to Non-Legal Asset Retirement Obligations
By Michael J. Majoros, Jr.
June 9, 2003**

Introduction

This summary and analysis provides the background required to understand the accounting and ratemaking implications of FERC Order No. 631 Accounting, Financial Reporting and Rate Filing Requirements for Asset Retirement Obligations as it relates to assets for which asset retirement obligations *do not* exist. It was prepared by Michael J. Majoros, Jr. who has closely followed and testified about the issue. Mr. Majoros attended the FERC Commission staff's May 7, 2002 Technical Conference on the subject and in conjunction with his partner Charles W. King prepared the Comments of the National Association of State Utility Consumer Advocates ("NASUCA") in FERC Docket No. RM02-7-000 which is manifested in FERC Order No. 631.

Background

In June 1994, at the request of the Edison Electric Institute ("EEI"), the Financial Accounting Standards Board ("FASB" or "Board") added an agenda project to focus on accounting for decommissioning costs of nuclear power plants. The original scope of the project related to the legal costs of decommissioning a nuclear power plant imposed by the Nuclear Regulatory Commission. Subsequently, the scope was expanded to include (a) similar legal obligations in other industries and (b) constructive obligations. In February 1996, the Board issued an Exposure Draft, *Accounting for Certain Liabilities Related to Closure or Removal of Long-Lived Assets.*[1]

SFAS No. 143

After two Exposure Drafts and several rounds of comments, FASB issued, in June 2001, its resulting Statement of Financial Accounting Standards No. 143, *Accounting for Asset Retirement Obligations* ("SFAS No. 143"). This statement addresses financial accounting and reporting for obligations associated with the retirement of tangible long-lived assets and the associated asset retirement costs. SFAS No. 143 applies to all entities [including public utilities] and "components of transmission and distribution systems (utility poles) etc," are specifically not excluded. (SFAS No. 143, paragraph B17, footnote 22.)

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[1] FASB Accounting for Obligations Associated with the Retirement of Long-Lived Assets. Staff summary of Board decisions, http://www.rutgers.edu/Accounting/raw/fasb/project/aro

It applies to *unambiguous* legal obligations associated with the retirement of long-lived assets that result from the acquisition, construction, development and (or) the normal operation of a long-lived asset, except for certain obligations of lessees. As used in SFAS No. 143, a legal obligation is an obligation that a party is required to settle as a result of an existing or enacted law, statute, ordinance, or written or oral contract or by legal construction of a contract under the doctrine of promissory estoppel.[2] SFAS No. 143 is effective for all financial statements issued for fiscal years beginning after June 15, 2002.

As indicated, SFAS No. 143 establishes accounting standards for recognition and measurement of a liability for an *asset retirement obligation* ("ARO") and the associated *asset retirement cost* ("ARC"). An asset retirement obligation refers to an obligation associated with the retirement of a tangible long-lived asset. The term asset retirement cost refers to the amount capitalized that increases the carrying amount of the long-lived asset <u>when a liability for an asset retirement obligation is recognized</u>.[3]

In general, SFAS No. 143 requires all entities to conduct reviews of their long-lived assets to determine whether they have AROs based on the legal standards summarized above. If an ARO exists, the entity must measure the ARC and <u>record a liability</u> for the amount and capitalize it as part of the original cost of the asset.

In explaining why it adopted this approach, the FASB stated that "paragraph 37 of [its] Statement 19 states that 'estimated dismantlement, restoration, and abandonment costs [future cost of removal]...shall be taken into account in determining amortization and depreciation rates.' Application of that paragraph has the effect of accruing an expense irrespective of the requirements for liability recognition in FASB Concepts Statements. In doing so, it results in [the anomalous] recognition of accumulated depreciation that can exceed the historical cost of a long-lived asset. The Board concluded that an entity should be precluded from including an amount for an asset retirement obligation in the depreciation base of a long-lived asset unless that amount also meets the recognition criteria in this Statement [SFAS No. 143]. When an entity recognizes a liability for an asset retirement obligation, it also will recognize an increase in the carrying amount of the related long-lived asset. Consequently, <u>depreciation of that asset will not result in the recognition of accumulated depreciation in excess of the historical cost of a long-lived asset</u>."[4]

Paragraph 37 eliminates any doubt as to the FASB's intent regarding the application of SFAS No. 143. All companies must review their long-lived assets to determine whether they have unambiguous legal asset retirement obligations associated with those assets. If they do have such obligations, then the estimated ARC (which is based on its estimated present value and updated annually following the rules in the Statement) is capitalized as part off the cost of the asset. Thus, at the end of the asset's

[2] SFAS No. 143, Summary, and Paragraph 2, and Appendix A, Paragraph A3.
[3] Id., Paragraph 1 and Footnote 1.
[4] Id., Paragraph B22. Emphasis added.

life, the accumulated depreciation account will be equal to the historical plant balance. In no case, may entities in general, include estimated future cost of removal in depreciation rates. Although SFAS No. 143 does not specifically state what to do with removal costs for assets which are not AROs, it is intuitively well accepted that concepts in the AICPA's SOP on Property, Plant and Equipment will eventually be adopted, and at least will not be objectionable. Those concepts would support expensing as incurred, or capitalization as a cost of the replacement.

Regardless of these overall principles and concepts, SFAS No. 143 recognizes that historically, many public utility depreciation rates contained a component for future cost of removal in the rate calculation. It deals with this issue as follows. "Many rate-regulated entities currently provide for the costs related to asset retirement obligations in their financial statements and recover those amounts in rates charged to their customers. Some of those costs relate to asset retirement obligations within the scope of this Statement; others are not within the scope of this Statement and, therefore, cannot be recognized as liabilities under its provisions. The objective of including those amounts in rates currently charged to customers is to allocate costs to customers over the lives of those assets. The amount charged to customers is adjusted periodically to reflect the excess or deficiency of the amounts charged over the amounts incurred for the retirement of long-lived assets. The Board concluded that if asset retirement costs are charged to customers of rate-regulated entities but no liability is recognized, a regulatory liability should be recognized if the requirements of SFAS No. 71 are met."[5]

Thus if the utility has included future net salvage in the past for which it has no ARO, then it will recognize and record a Regulatory Liability to ratepayers for that amount on its financial books and records. Presumably, if the utility continues to include future cost of removal in its depreciation rates, the Regulatory Liability to Ratepayers will also continue to grow.

In summary, SFAS No. 143 precludes the inclusion of future net salvage in depreciation rates for all entities in general, based on the principles and concepts included therein. However, recognizing the unique aspects of rate-regulated entities, SFAS No. 143 requires that those unique aspects be accounted for in a Regulatory Liability to Ratepayers.

FERC Docket No. RM02-7-000

On March 29, 2002, the FERC Commission staff announced that it would hold a technical conference to discuss the financial accounting, reporting and ratemaking implications related to asset retirement obligations associated with the retirement of tangible long-lived assets.[6] "The main purpose for convening this technical conference is to afford an opportunity for the electric, natural gas and oil pipeline industries and other

[5] Id., Paragraph B72.
[6] Federal Energy Regulatory Commission, Docket No. RM02-7-000, Notice of Informal Technical Conference, Agenda and Request for Comments, (March 29, 2002). ("Notice".)

interested parties to discuss with the Commission staff issues related to the implementation of accounting requirements for asset retirement obligations. The goal of the conference is to identify how recognition of asset retirement obligations may affect the Commission's existing accounting and rate regulations."[7] The FERC Notice also requested comments on the subject.

Several comments were received and the Technical Conference was held at the FERC in Washington, D.C. on May 7, 2002. Several parties attended, and several panels were heard, followed by a question and answer session. The subjects of ARO's and SFAS No. 143 were intertwined through virtually all comments. Subsequently, on October 30, 2002, the FERC Issued a Notice of Proposed Rulemaking ("NOPR") in Docket RM02-7-000. The FERC proposed to revise its regulations to update the accounting and reporting requirements for liabilities for asset retirement obligations under its Uniform Systems of Accounts for public utilities, licensees, natural gas companies, and oil pipeline companies.[8]

The NOPR stated that "the proposed accounting for asset retirement obligations is consistent with the accounting and reporting requirement that jurisdictional entities will use [SFAS No. 143] in their general purpose financial statements provided to shareholders and the Securities and Exchange Commission. (e.g., companies will separately account and report the liability for asset retirement obligations, capitalize the asset costs, and charge earnings for depreciation of the asset and operating expense for the accretion of the liability)."[9]

The NOPR went on to say "the recognition and measurement of legal liabilities associated with the retirement and decommissioning of long-lived assets by various entities, including Commission jurisdictional entities, has been inconsistent over the years. The usefulness of consistently recognizing and measuring asset retirement obligations in the financial statements resulted in Financial Accounting Standards Board (FASB) issuing a new accounting pronouncement affecting the manner in which legal obligations are measured and reported in the financial statements applicable to entities in general.6" The NOPR's footnotes 6 to 12 then cited to various paragraphs and concepts contained in SFAS No. 143. The NOPR generally proposed to adopt and integrate SFAS No. 143 into its Uniform System of Accounts, and Reporting Requirements and then established certain ratemaking standards.

Regarding non-legal retirement obligations the NOPR stated "the Commission is aware that a number of natural gas companies are currently collecting an allowance in jurisdictional rates to cover the future cost of retiring and removing facilities. This allowance is referred to as a negative salvage allowance. The Commission believes that these negative salvage allowances do not necessarily reflect the existence of a legal asset

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[7] Notice page 3.
[8] FERC Docket No. RM02-7-000, Notice of Proposed Rulemaking, Issued October 30, 2002, ("NOPR"), page 1.
[9] Id., Paragraph I.2.

retirement obligation. Therefore, the Commission will require that negative net salvage allowances that are not established due to an asset retirement obligation be identified for ratemaking purposes separately from asset retirement obligation allowances. The current rate change filing requirements for natural gas companies at 154.312(d), Statement D, requires that any authorized negative salvage must be maintained in a separate subaccount of account 108, Accumulated provision for depreciation of gas utility plant. The Commission proposes to amend this section to ensure that this subaccount must not include any amounts related to asset retirement obligations."[10] The NOPR did not specifically identify electric utilities in this regard. Again, comments were requested and received, and on April 9, 2003 the FERC issued its Final Rule, i.e. Docket No. RM02-7-000, Order No. 631.

Order No. 631

Order No. 631 states "instead, we will require jurisdictional entities to maintain separate subsidiary records for cost of removal for non-legal retirement obligations that are included as specific identifiable allowances recorded in accumulated depreciation in order to separately identify such information to facilitate external reporting and for regulatory analysis, and rate setting purposes. Therefore, the Commission is amending the instructions of accounts 108 and 110 in parts 101, 201 and account 31, Accrued depreciation-carrier property, in Part 352 to require jurisdictional entities to maintain separate subsidiary records for the purpose of identifying the amount of specific allowances collected in rates for non-legal retirement obligations included in the depreciation accruals.[11]

"Jurisdictional entities must identify and quantify in separate subsidiary records the amounts, if any, of previous and current accumulated removal costs for other than legal retirement obligations as part of the depreciation accrual in accounts 108 and 110 for public utilities and licensees, account 108 for natural gas companies, and account 31 for oil pipeline companies. If jurisdictional entities do not have the required records to separately identify such prior accruals for specific identifiable allowances collected in rates for non-legal asset retirement obligations recorded in accumulated depreciation, the Commission will require that the jurisdictional entities separately identify and quantify prospectively the amount of current accruals for specific allowances collected in rates for non-legal retirement obligations."[12]

Order No. 631 also states "the Commission will decline to make policy calls concerning regulatory certainty for disposition of transition costs, external funds for amounts collected in rates for asset retirement obligations, adjustments to book depreciation rates, and the exclusion of accumulated depreciation and accretion for asset retirement obligations from rate base; these are matters that are not subject to a one size fits all approach and are better resolved on a case-by-case basis in rate proceedings. The

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[10] Id., Paragraph III 45.
[11] FERC Docket No. RM02-7-000, Order No. 631, Issued April 9, 2003, Paragraph 39.
[12] Id., Paragraph 39.

Commission is of the view that utilities will have the opportunity to seek recovery of qualified costs for asset retirement obligations in individual rate proceedings. This rule should not be construed as pregranted authority for rate recovery in a rate proceeding."[13]

Order No. 631 goes on to say "finally this rule requires nothing new and nothing more with respect to the requirement for a detailed study. Complex depreciation and negative salvage studies are routinely filed or otherwise made available for review in rate proceedings. When utilities perform depreciation studies, a certain amount of detail is expected. It is incumbent upon the utility to provide sufficient detail to support depreciation rates, cost of removal, and salvage estimates in rates.45." [14] And footnote 45 states "when an electric utility files for a change in its jurisdictional rates, the Commission requires detailed studies in support of changes in annual depreciation rates if they are different from those supporting the utility's prior approved jurisdictional rate."[15]

Thus, it seems clear that the FERC recognizes distinctions between legal and non-legal AROs just as SFAS No. 143 recognizes those distinctions. In fact, the amount resulting from Order No. 631's requirement to identify previous amounts collected for non-legal ARO's should result in the same amount as the SFAS NO. 143 requirement to establish a regulatory liability to ratepayers for the same amounts. It is also clear, that on a going-forward basis, jurisdictional entities must be prepared to specifically identify and justify any non-legal AROs that they propose to be included in their rates.

[13] Id., Paragraph 64. (Emphasis added.)
[14] Id., Paragraph 65.
[15] Id., footnote 45.

KENTUCKY UTILITIES COMPANY

CASE NO. 2003-00434

Response to First Data Request of Commission Staff Dated December 19, 2003

Question No. 56

Responding Witness: Valerie L. Scott

Q-56. Provide complete details of KU's financial reporting and rate-making treatment of SFAS No. 143, including:

a. The date that KU adopted SFAS No. 143.

b. All accounting entries made at the date of adoption.

c. All studies and other documents used to determine the level of SFAS No. 143 cost recorded by KU.

d. A schedule comparing the depreciation rates utilized by KU prior to and after the adoption of SFAS No. 143. The schedule should identify the assets corresponding to the affected depreciation rates.

A-56. a. KU adopted SFAS No. 143 as of January 1, 2003.

b. See attached. for accounting entries made to adopt SFAS No. 143.

c. See attached for documents used to determine the level of SFAS No. 143 cost recorded by KU. Please note that information protected from disclosure by the attorney-client privilege has been redacted.

d. See attached for a schedule comparing the depreciation rates utilized by KU prior to and after the adoption of SFAS No. 143. For underlying assets Kentucky Utilities Company utilized the depreciation rates approved by the Commission in Case No. 2001-140 both prior to and after the adoption of SFAS No 143. For ARO assets set up pursuant to SFAS No. 143, Kentucky Utilities Company utilized the rates approved by the Commission in Case No. 2001-140 excluding the net salvage component.

LG&E Energy Corp.

Supporting Papers
SFAS 143 Implementation

December 30, 2002

Executive Summary

In June 2001, the Financial Accounting Standards Board (FASB) issued Statement of Financial Accounting Standards No. 143, Accounting for Asset Retirement Obligations. LG&E Energy Corp. and associated Companies (the Company) intend to adopt Statement 143 as of January 1, 2003.

Statement 143 results in significant accounting change for the Company and its regulated utilities. The standard changes the way companies recognize and measure legal retirement obligations that result from the acquisition, construction and normal operation of tangible long-lived assets. A legal obligation is an obligation that a party is required to settle as a result of an existing or enacted law, statute, ordinance, or contract.

Prior to Statement 143, the Company's regulated utilities accrued retirement and removal costs as a component of depreciation expense. SFAS 143 prohibits this approach for assets within its scope. Asset retirement obligations (AROs) must now be recognized as a liability and measured at fair value. The cost associated with the recognition of the asset retirement obligation is capitalized as part of the related asset's book cost and is depreciated over the expected life of the asset.

The asset retirement obligation is initially recorded at fair value. In each subsequent period, the liability is increased through the recognition of accretion expense. Much as depreciation expense allocates the cost of installing an asset over its useful life, accretion expense allocates the cost of removing an asset over its useful life. Accretion expense appears as an operating expense in the income statement.

At adoption the Company must recognize the cumulative effect of applying the statement as a change in accounting principle. The amount reported as a cumulative effect adjustment in the statement of operations is the difference between the amounts recognized in the statement of financial position prior to the application of Statement 143 and the net amount that is recognized in the financial statements by applying the standard. Asset retirement obligations that are currently recorded by the regulated utilities as part of accumulated depreciation will be reversed as part of the cumulative effect adjustment.

The Company expects to book significant ARO assets and liabilities related to its regulated utilities. However the Company expects the standard to be revenue neutral for its utility operations through the application of SFAS 71, Accounting for the affects of Certain Types of Regulation. (See Appendix H, pg. 21)

Planning

The Company began planning for SFAS 143 in the 4th quarter of 2001. A four-stage implementation timeline was developed consisting of analysis, planning, implementation and adoption stages.

The planning stage involved developing the proper approach, reactions and strategies. It also involved communication with regulators, outside auditors and industry members and associations to evaluate consistency with the industry.

During 2001 and 2002 the Company participated in numerous industry and regulatory forums to gain an understanding of the standard and to ensure consistency with the industry. These forums included:

EEI Asset Retirement Obligations Seminar – October 2001

EEI Roundtable Discussion on Accounting for AROs – March 2002

EEI – FERC Accounting Liaison meeting April 2002

FERC Technical Conference – May 2002

AGA/EEI ARO Seminar – July 2002

EEI – FERC Accounting Liaison meeting October 2002

Through its participation in these forums the Company has developed an understanding of the standards' technical requirements consistent with the industry. The Company advocated this understanding before the Federal Energy Regulatory Commission at the EEI – FERC Accounting Liaison meetings in April and October 2002. On April 9, 2003 the FERC issued Final Order No.631 'Accounting Reporting and Rate Filing Requirements for Asset Retirement Obligations" in Docket No. RMO2-7-000. The Final rule was consistent in all material respects with the company's understanding of SFAS 143.

The Final Rule in effect revises the FERC chart of accounts to accommodate FAS 143 accounting. Specifically it establishes new balance sheet accounts for the ARO assets and liabilities. It also establishes new income statement accounts for accretion and depreciation expense. In addition, the NOPR grants utilities the authority to transfer removal costs previously accrued under regulatory accounting practices to the new liability accounts. Thus, all ARO assets within the scope of SFAS 143 will be subject to the new FERC accounting procedures. Current regulatory depreciation practices remain in place for all non-ARO assets. Because the Final Rule provides for the establishment of regulatory assets and liabilities when companies meet the requirements of SFAS 71, the Company expects SFAS 143 to be revenue neutral for its regulated entities.

Analysis

The analysis stage, which also began in first quarter 2002, was a coordinated effort of accounting, legal, environmental, operations and senior management personnel. The determination of whether assets are within the scope of Statement 143 is essentially a review of legal documents past and present that relate to the purchase, construction, development, or normal operation of the asset. The Company has numerous tangible long-lived assets that were constructed over many decades. Thus, significant effort and resources were required to identify the legal obligations associated with plant assets.

The Company addressed the analysis stage from both a legal and operations perspective. First, a working group was assembled representing legal, accounting, environmental and operating personnel. This group was trained on the standard, including what qualified as an ARO and how to identify qualifying AROs, prior to the identification process

The legal department was then asked to perform a review of legal documents including laws, statutes, contracts, permits, certificates of need and right of way agreements. Operations personnel were asked to identify and quantify known retirement and removal activities undertaken within their group for review as a potential ARO. The environmental group was asked to identify any environmental regulation that obligated the company upon disposal of an asset.

Through this process, a preliminary inventory of ARO assets was quantified for each functional group and the relevant legal requirement was documented. Preliminary results by functional group are as follows.

Generation

Neither LG&E nor KU identified a legal obligation to demolish steam generating plants or restore the land to "green field condition" when a power plant is decommissioned. The utilities' past practice has been to secure retired generating sites in a safe manner and abandon the plant in place. Although no legal obligation exists for the generating units as a whole, both utilities identified AROs associated with component assets when a generating plant is decommissioned. These AROs primarily arise from environmental regulation.

The preliminary inventory of steam generation obligations were identified, in part, based on the Company's recent experience with the retirement of its Pineville generating unit. The Pineville generating unit failed in early 2002 and was retired from the Company's' books. Because the failure and retirement occurred prior to the implementation of SFAS 143 it was not within the scope of the statement. However, based on that experience, operating personnel developed an inventory of potential AROs and actual third party decommissioning costs related to steam generating assets. Potential AROs identified included:

Holding pond remediation

Coal and limestone storage pile remediation

Boiler water remediation

Oil storage tank remediation

Removal and disposal of underground storage tanks

Empty and remediate all above ground hazardous material storage

Remove and remediate all mercury sources

Drain generation step up transformers and wrap in nitrogen blanket

Ground water monitoring

In addition to the potential AROs suggested by the Pineville experience, the evaluation included a search for potential AROs that were not pertinent to Pineville, but might relate to another facility. Each power plant manager was asked to evaluate the retirement activities necessary at their location to identify potential AROs specific to that location.

Once generation personnel developed the inventory of potential AROs, the Environmental Department was asked to document the regulatory requirement giving rise to the obligation, When no environmental obligation was found the legal department was asked to review the potential ARO to determine if any legal obligation existed. Through this process, the Company was able to establish a definitive legal/regulatory obligation for each ARO included in the final inventory.

The Company's findings based on actual experience at Pineville and the input of power plant managers are consistent with the industry white paper published by the Edison Electric Institute (EEI) in August 2002.

Hydro Generation

LG&E operates its Ohio Falls plant under a 30-year licensing agreement with the U.S. Army Corps of Engineers. This agreement requires the dam to be restored to the Corps' specifications upon abandonment of the plant. The cost of this restoration is estimated at $8 million. The Company has renewed the licensing agreement with the Corps of Engineers continually since the plants' construction and expects to renew the agreement continually at each expiration date. Therefore, because the hydro plant has an indeterminate retirement date no ARO liability is being established at this time.

KU owns two hydro facilities, Dix Dam and Lock 7. Estimated decommissioning costs for these plants are $1.3 million and $3.4 million respectively. However, a legal review the hydro licenses found no specific legal obligation upon the final decommissioning of these plants. It should be noted, however, that permitting authorities, particularly FERC, have significant inherent discretion in setting conditions to permit a surrender of a permit. These conditions are based upon the specific facts, issues and concerns at the time of decommissioning. In the case of Lock 7, a study determined that it was likely that surrender of the FERC permit would involve both removal of generation equipment and demolition of station down to water line. Because no specific legal liability was identified and the retirement date is indeterminate no ARO liability is being established at this time.

Electric Transmission and Distribution Plant

In general, the Company and the industry operate its transmission and distribution (T&D) lines as if the assets will be operated into perpetuity. Even if the utility were to cease business, it is more likely than not that another energy company would simply takeover the lines.

LG&E and KU own transmission and distribution lines that operate under perpetual property easement agreements. These easements do not generally require restoration of the right of way or removal of the property. If an easement were to be released, the company would retire the equipment in place and maintain it in a safe manner.

However, there are components of T&D that have retirement obligations associated with them due to environmental or other contractual agreements. KU and LG&E have certain electrical equipment containing PCBs, such as transformers and capacitors, which require special disposal. Both companies undertook a program in the 1980's to replace this PCB impaired equipment. Thus the companies have few if any obligations related to PCB contamination. The retirements related to these assets were addressed for frequency and materiality to determine if the interim retirement would fall within the scope of SFAS 143 as described below.

Per Mike Toll Manager Transmission Planning and Substations, there are no legal or environmental requirements for disposal of station transformers. Other substation equipment such as bushings may have some obligation related to PCB contaminants. If so, this equipment must be disposed of per EPA regulation. However the cost, less than $20K per year, is immaterial. In 2002, the Company disposed of four assets at a cost of $17K. The 2002 activity was higher than normal according to Mike Toll. In addition, specific assets impacted are not identifiable until failure or replacement.

Per Andre Johnson, Team Leader Environmental and Transformer Services, PCB contaminated line transformers must be disposed of per environmental regulation. The company disposes of PCB contaminated line transformers through a third party vendor. LG&E costs were approximately $10K in 2002. KU costs were approximately $42K in 2002. Based on 2002 disposals the cost of this activity on an annual basis is immaterial. In addition, specific assets impacted are not identifiable until failure or replacement.

Both utilities determined that the retirement of T&D generation step up transformers are within the scope of SFAS 143 since a final retirement date and decommissioning costs could be reasonably estimated. These transformers are located at the generating stations and subject to certain environmental requirements upon final retirement of the generating units. No other AROs were identified related to interim T&D retirements.

In summary, LG&E and KU have identified certain T&D obligations related to the final retirement of generating units. No other material retirement obligations were identified for Electric Transmission and Distribution. In addition, the Company's T&D system as a whole is being operated as a perpetual asset. Therefore, the retirement date is indeterminate and no ARO can be calculated. This position is consistent with both the EEI white paper and industry practice.

Gas Transmission and Distribution Plant

LG&E owns a gas transmission and distribution system that operates under perpetual property easement agreements. If an easement were to be released, the Company does not have an obligation to remove the system but retires it in place. The Company operates the gas transmission and distribution system as if the assets will be operated into perpetuity. Even if the utility were to cease business, it is more likely than not that another energy company would takeover the lines.

However, LG&E operates wells in its gas storage system that must be plugged if abandoned, per Kentucky mines & minerals law/regulations. Because LG&E intends to operate the wells perpetually and the retirement date is indeterminate, no ARO has been established. The estimated cost of plugging the 546 wells is $17 thousand per well or $9.2 million in total.

LG&E also operates 4 above ground gas compressor stations under perpetual lease agreements. The ground leases for the Muldraugh KY, Cedar Fields IN, and Brandenburg KY (Riggs and Doe Run sites) were reviewed for contractual obligations. A 1946 letter of agreement to the Brandenburg KY (Riggs site) lease requires LG&E to "return it to lessor on the expiration of the this lease in approximately the same condition as found at the present time." The estimated cost to dismantle and remove the Brandenburg station is $48 thousand.

Beyond the above, the leases did not contain any required actions upon abandonment except an obligation to pay $1 to terminate the lease itself. (Additionally, under the Muldraugh lease, LG&E is permitted, but not required to remove equipment. Facilities left after termination become government property.)

Because the review of the agreements revealed no legal obligations, other than for the Brandenburg/Riggs site, no AROs are being established. In addition because the Brandenburg/Riggs site is operated as a perpetual asset with an indeterminate retirement date no ARO is being established for that site. However the estimated costs of the Brandenburg/Riggs contractual obligation is being disclosed in the footnotes to the financial statements.

In summary, LG&E has identified certain immaterial obligations related to the abandonment of its gas storage wells and the Brandenburg compressor station. No other AROs have been identified for Gas Transmission and Distribution. Because the system is being operated as a perpetual asset and the retirement date is indeterminate no AROs are being established. The amount of the potential obligation at the Brandenburg site is being disclosed in the footnotes to the financial statements. This position is consistent with both the EEI white paper and industry practice.

Cash Flow Modeling

Concurrent with the identification of potential AROs, the company has developed a cash flow model to calculate and comply with the various recognition and measurement provisions of the standard. (See Appendix A) The model calculates:

1. The amount of the ARO asset and liability to be established as of the original in service date
2. Annual accretion expense from the original in service date
3. The cumulative ARO liability at the transition date
4. Depreciation expense on ARO asset from the original in service date
5. Cumulative depreciation on ARO asset at the transition date
6. Depreciation and Removal cost related to underlying asset from the original in service date
7. Regulatory asset/liability due to the difference between regulatory and GAAP accounting methods

Inputs to the model are as follows:

1. Asset original cost – Original installation costs per company fixed asset records. This is the basis for determining removal costs previously accrued through regulatory depreciation.
2. Regulatory depreciation rate- Depreciation rate established in Company's most recent depreciation study.
3. Salvage rate- Calculated rate based on net salvage data from Company's most recent depreciation study. This represents the removal cost component of regulatory depreciation rates.
4. GAAP depreciation rate- the regulatory depreciation rate less the salvage rate. This represents depreciation allowable under SFAS 143. This rate is applied to the ARO asset and the underlying tangible asset going forward.
5. In service date- Original asset in service date per company fixed asset records.
6. Retirement date- Estimated retirement date based on Company's most recent depreciation study.
7. Discount rate-Current corporate utility bond index rate for A rated issuers as reported by Bloomberg. 6.61 % as of December 2002.
8. Inflation rate- 30-year Treasury bond rate less 30-year inflation adjusted bond rate as reported by Bloomberg. 2.1% as of November 2002.

9. ARO in Current $- Estimated fair market cost to settle obligation today

Accounting Systems

Based on the guidance issued in the FERC Final Order, the Company believes that significant software modifications are not necessary to implement SFAS 143. Because the number of AROs is limited, the company expects to track AROs with its current accounting system and spreadsheet applications. The Company's chart of accounts and accounting systems were modified to reflect the new income statement and balance sheet accounts established in the FERC NOPR.

Accounting Procedures

The FERC Final Order on SFAS 143 requires that the Company keep subsidiary records and supporting documentation for each asset retirement obligation. The Company must record the identity and nature of the legal obligation, the year incurred, the underlying asset giving rise to the obligation and supporting computations related to the measurement of the obligation. The Company has revised its accounting procedures to comply with the FERC requirements as follows.

Initial ARO Establishment-

1. ARO Asset-Upon establishment of an ARO, an asset equivalent to the present value of the retirement obligation is established in the appropriate FERC plant account of the ORACLE fixed asset module. The fixed asset records shall include a description of the ARO asset including the underlying tangible asset #, the amount of the asset, the FERC plant account, the location code, the original in service date and the estimated retirement date
2. Underlying Tangible Asset-The ARO asset is linked to the underlying tangible asset in existing records by referencing the asset number of the underlying asset in the description field of the ARO asset.
3. ARO Liability-An offsetting liability is established in account 230 by creating a distinct and separate project for each ARO liability in the ORACLE project accounting module. The project accounting records shall include a description of the ARO liability, the related ARO asset #, the underlying tangible asset #, the amount of the original liability, the location code, the ARO inception date and the expected settlement date

Depreciation

1. ARO Asset - Depreciation expense related to the intangible ARO asset is charged to account 403.1, "Depreciation for Asset Retirement Costs". A corresponding credit is charged to Account 108.1 "Accumulated Reserve for Depreciation of ARO Assets"
2. Underlying Tangible Asset - Depreciation expense related to the underlying tangible asset is charged to account 403 "Depreciation Expense." A corresponding credit is charged to Account 108 "Accumulated Provision for Depreciation of Electric Utility Plant".

3. Depreciation rates – The depreciation rate approved by the Public Service Commission for regulatory accounting purposes is applied to the underlying asset. However, because SFAS No. 143 does not allow the accrual of removal costs through depreciation for assets within its scope and because the Company qualifies for SFAS 71 treatment, a regulatory asset or liability will be established to record the difference between depreciation allowed by regulators and that allowed by GAAP.

   The depreciation rate allowed by GAAP is applied to the ARO asset going forward. The GAAP rate is the rate approved in the Company's most recent depreciation study less the net salvage component.

Accretion

1. Accretion expense – Accretion expense is charged to account 411.10, "Accretion Expense". A corresponding credit is charged to Account 230 "Asset Retirement Obligations"

Cumulative Effect adjustment

1. The cumulative effect adjustment is established by a debit to account 435 "Extraordinary Deductions". Offsetting credits are charged to account 230, "Asset Retirement Obligations" for the accumulated accretion and to Account 108.1, "Accumulated Reserve for Depreciation of ARO Assets" for accumulated depreciation. (The cumulative effect adjust is equivalent to the total accumulated accretion and depreciation expense that would have been accrued if the liability had been established at the time the liability was originally incurred, less any removal costs accrued through regulatory depreciation)

Regulatory Assets and Liabilities

1. Regulatory Assets –Pursuant to SFAS 71, depreciation and accretion expense related to the ARO asset and liability is offset with a regulatory asset. The regulatory asset is established by a debit to account 182.3, "Regulatory Assets". A corresponding regulatory credit is established in account 407.4 "Other Regulatory Credits". (See Appendix I)
2. Regulatory Liabilities – Pursuant to SFAS 71 previously accrued removal costs in excess of that allowed under SFAS 143 is offset with a regulatory liability. The regulatory liability is established by a credit to account 254, "Regulatory Liabilities". A corresponding debit is established in account 407.3 "Other Regulatory Debits"

Settlement

1. Gain on Settlement – Gains resulting from the settlement of an asset retirement obligation are charged to account 411.6, "Gains from Disposition of Utility Plant"
2. Loss on Settlement - Losses resulting from the settlement of an asset retirement obligation are charged to account 411.7, "Losses from Disposition of Utility Plant"(see Appendix H)

Identifying Removal Costs Currently Recorded

The Company estimated the amount of removal costs related to AROs recorded in its accumulated reserve. The estimate is based on data from the Company's most recent depreciation study. Based on that study the Company determined the removal cost component inherent in each depreciate rate. That removal cost component is applied to the original cost and in-service date of the underlying asset to estimate the removal cost accrued for the specific asset. The estimated removal costs related to ARO assets was removed from the accumulated reserve pursuant to the FERC Final Order No.631 'Accounting Reporting and Rate Filing Requirements for Asset Retirement Obligations".

Subsequent to the Company's implementation of SFAS 143 the FERC issued its Final Order No. 631. The order required Companies to estimate the cost of removal embedded in the accumulated reserve for non-ARO assets and to segregate those cost within Account 108 for reporting purposes.

Pursuant to that Order, the Company contracted for an independent analysis of non-ARO removal costs to be performed in conjunction with its 2003 depreciation study. That analysis was completed and in December 2003 a journal entry was prepared segregating those removal costs within FERC Account 108 "Accumulated Provision for Depreciation of Electric Utility Plant".

Implementation

In the implementation stage which began in the 3rd quarter 2002, t the company;

1. Identified removal cost previously accrued
2. Determined ARO asset write-ups
3. Quantified regulatory assets/liabilities
4. Modified accounting Systems
5. Revised Accounting Policies
6. Communicated with Regulatory Agencies
7. Discussed implications with the Tax Department
8. Drafted required financial footnotes and disclosures
9. Obtained final management approval
10. Obtained final verification that all regulatory requirements have been identified
11. Verified consistent application across all assets
12. Verified that all obligations identified are included in the calculations
13. Verified that obligations exist for all assets included
14. Ensured compliance with the final FERC order
15. Reviewed final product with PriceWaterhouseCoopers

Adoption
The company adopted SFAS 143 effective January 1, 2003.

Appendix A

SFAS 143 Cash Flow Model Summary

(See cash flow binder for detail by location)

CALCULATION OF FAS ... T RETIREMENT OBLIGATION
and Tra... s at 01/01/2003

Louisville Gas and Electric Company

Estimated Settlement Cost Current $			20,008
FV Estimated Settlement Cost at	2.10%	Inflation	33,470
PV Settlement Cost at	5.61%	Discount Rate	2,746

Transition Journal Entries @ 01/01/03

	Dr	Cr
ARO Asset	2,745.8	-
Reg Asset	5,063.5	-
Reg Credits	-	5,063.5
Extr. Deductions	5,063.6	-
Reg Liability	-	104.0
Acc Depreciation	630.8	860.7
ARO Liability	-	7,475.2
	13,503.48	13,503.48

2003 Post Implementation Journal Entries

	Dr	Cr
Accretion Expense	368.5	-
Depreciation Expense	42.3	-
Reg Assets	406.8	-
Acc Depreciation	-	42.3
ARO Liability	-	368.5
Reg Credits	-	406.8
	-	-
	817.68	817.68

Accretion Expense	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013
Cane Run	221	236	252	268	286	305	325	346	369	394	420
Mill Creek	-	-	-	-	-	-	-	-	-	-	-
Trimble County	148	155	165	176	188	200	213	227	242	258	275
Annual Accretion	368	391	417	444	473	505	538	574	612	652	695
Depreciation Expense											
Cane Run	19	19	19	19	19	19	19	19	19	19	19
Mill Creek	-	-	-	-	-	-	-	-	-	-	-
Trimble County	24	24	24	24	24	24	24	24	24	24	24
Annual Depreciation	42	42	42	42	42	42	42	42	42	42	42
Total Dep/Accr.	409	433	459	486	516	547	580	616	654	694	737
Regulatory Credits	409	433	459	486	516	547	560	616	654	694	737
Total I/S Effect-LGE	-	-	-	-	-	-	-	-	-	-	-

Accretion Expense	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Cane Run	447	477	509	541	576	11	11	11	11	11	11	11
Mill Creek	-	-	-	-	-	-	-	-	-	-	-	-
Trimble County	294	313	334	356	379	404	431	460	490	522	557	594
Annual Accretion	741	790	842	897	956	416	443	471	501	534	568	605
Depreciation Expense												
Cane Run	19	19	19	19	19	-	-	-	-	-	-	-
Mill Creek	-	-	-	-	-	-	-	-	-	-	-	-
Trimble County	24	24	24	24	24	24	24	24	24	24	24	24
Annual Depreciation	42	42	42	42	42	24	24	24	24	24	24	24
Total Dep/Accr.	783	832	885	940	998	439	466	495	525	557	592	629
Regulatory Credits	783	832	885	940	998	439	466	495	525	557	592	629
Total I/S Effect-LGE	-	-	-	-	-	-	-	-	-	-	-	-

Kentucky Utilities Company

Estimated Settlement Cost Current $			34,146
FV Estimated Settlement Cost at	2.10%	Inflation	54,334
PV Settlement Cost at	5.61%	Discount Rate	7,289

Transition Journal Entries @ 01/01/03

	Dr	Cr
ARO Asset	7,289	-
Reg Asset	6,227	-
Reg Credits	-	6,227
Extr. Deductions	6,227	-
Reg Liability	-	1,626
Acc Depreciation	3,652	1,572
ARO Liability	-	13,780
	23,404.69	23,404.69

2003 Post Implementation Journal Entries

	Dr	Cr
Accretion Expense	786.0	-
Depreciation Expense	187.7	-
Reg Assets	973.7	-
Acc Depreciation		187.7
ARO Liability		786.0
Reg Credits		973.7
		0.1
	1,947.41	1,947.51

Accretion Expense	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013
Ghent	437	466	497	529	564	602	642	684	729	777	829
Brown	340	372	397	423	451	481	512	546	582	621	662
Tyrone	-	-	-	-	-	-	-	-	-	-	-
Green River	0	0	0	0	0	0	0	0	0	0	0
Annual Accretion	786	834	893	952	1,015	1,082	1,154	1,230	1,312	1,398	1,491
Depreciation Expense											
Ghent	114.02	114.02	114.02	114.02	114.02	114.02	114.02	114.02	114.02	114.02	114.02
Brown	73.70	73.70	73.70	73.70	73.70	73.70	73.70	73.70	73.70	73.70	73.70
Tyrone	-	-	-	-	-	-	-	-	-	-	-
Green River	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
Annual Depreciation	188	188	188	188	188	188	188	188	188	188	188
Total Dep/Accr.	974	1,026	1,081	1,140	1,203	1,270	1,342	1,418	1,499	1,586	1,678
Regulatory Credits	974	1,026	1,081	1,140	1,203	1,270	1,342	1,418	1,499	1,586	1,678
Total I/S Effect-LOE	-	-	-	-	-	-	-	-	-	-	-

Accretion Expense	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Ghent	884	942	712	759	810	863	919	906	966	1,029	1,097	1,167
Brown	706	751	801	854	910	969	88	94	100	107	114	15
Tyrone	-	-	-	-	-	-	-	-	-	-	-	-
Green River	0	0	0	0	0	-	-	-	-	-	-	-
Annual Accretion	1,589	1,693	1,513	1,613	1,720	1,832	1,007	1,000	1,066	1,136	1,211	1,182
Depreciation Expense												
Ghent	114.02	114.02	55.09	55.09	55.09	55.09	55.09	49.22	49.22	49.22	49.22	49.16
Brown	73.70	73.67	73.67	73.67	73.67	73.66	8.74	8.74	8.74	8.74	8.74	8.33
Tyrone	-	-	-	-	-	-	-	-	-	-	-	-
Green River	0.01	0.01	0.01	0.01	0.01	-	-	-	-	-	-	-
Annual Depreciation	188	188	129	129	129	129	64	58	58	58	58	58
Total Dep/Accr.	1,777	1,881	1,642	1,742	1,849	1,961	1,071	1,058	1,124	1,194	1,269	1,232
Regulatory Credits	1,777	1,881	1,642	1,742	1,849	1,961	1,071	1,058	1,124	1,194	1,269	1,232
Total I/S Effect-LOE	-	-	-	-	-	-	-	-	-	-	-	-

Total Utility

CALCULATION OF FAS' :T RETIREMENT OBLIGATION
and Tran. s at 01/01/2003
s)

Estimated Settlement Cost Current $			54,154
FV Estimated Settlement Cost at	2.10%	Inflation	67,684
PV Settlement Cost at	6.61%	Discount Rate	10,045

Transition Journal Entries @ 01/01/03

	Dr	Cr
ARO Asset	10,045	-
Reg Asset	11,290	-
Reg Credits	-	11,290
Ext. Deductions	11,290	-
Reg Liability	-	1,930
Acc Depreciation	4,283	2,433
ARO Liability	-	21,255
	36,908.17	36,908.17

2003 Post Implementation Journal Entries

	Dr	Cr
Accretion Expense	1,152.5	-
Depreciation Expense	230.1	-
Reg Assets	1,382.5	-
Acc Depreciation	-	230.1
ARO Liability	-	1,152.5
Reg Credits	-	1,382.5
	2,765.08	2,765.08

	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
Accretion	1,152	1,229	1,310	1,396	1,489	1,587	1,692	1,804	1,923	2,050	2,186	2,330
Depreciation	230	230	230	230	230	230	230	230	230	230	230	230
Total Utility Depr/Accrel	1,383	1,458	1,540	1,627	1,719	1,817	1,922	2,034	2,153	2,280	2,416	2,560
Regulatory Credits	1,383	1,459	1,540	1,627	1,719	1,817	1,922	2,034	2,153	2,280	2,416	2,560
Total IIS Effect-LGE	-	-	-	-	-	-	-	-	-	-	-	-

	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Accretion	2,483	2,355	2,510	2,675	2,248	1,450	1,471	1,567	1,670	1,779	1,788
Depreciation	230	171	171	171	152	87	81	81	81	81	73
Total Utility Depr/Accrel	2,714	2,526	2,681	2,847	2,400	1,537	1,552	1,649	1,751	1,861	1,861
Regulatory Credits	2,714	2,526	2,681	2,847	2,400	1,537	1,552	1,649	1,751	1,861	1,861
Total IIS Effect-LGE	-	-	-	-	-	-	-	-	-	-	-

Appendix B
Transition and Post implementation Journal entries

Total Utility Operations
ARO Journal Entries
($000's)

DESCRIPTION	Annual Amount DEBIT	CREDIT
JOURNAL ENTRIES REQUIRED AT IMPLEMENTATION		
Long Lived Assets - ARO - *(New Account)*	10,045	
COR Liability Accrued to Date	4,283	
Regulatory Asset	11,290	
Cumulative effect	11,290	
Regulatory Credits		11,290
Regulatory Liability (New Account)		1,930
Accumulated Depreciation of ARO Asset - *(New Account)*		2,433
ARO Liability - *(New Account)*		21,255
	36,908	36,908
To record the implementation of FAS 143		

DESCRIPTION	DEBIT	CREDIT
Long Lived Assets - ARO - BS Account 317	10,045	
ARO Liability - BS *Account 230*		10,045
To record the initial present value of ARO liability		

Upon implementation of FAS 143, the ARO liability (in current dollars) must be future valued at the anticipated inflation rate. The ARO liability must then be present valued back to when the liability was incurred using risk free rate plus risk premium at the time the liability was incurred.

The ARO asset is valued at the present value of the liability at the time the liability is incurred.

DESCRIPTION	DEBIT	CREDIT
Cumulative Effect Adjustment - IS Account 435	2,433	
Accumulated Depreciation of ARO Asset - *BS Account 108*		2,433
To record accumulated depreciation on ARO assets		

Assumes the ARO Asset is depreciated over the same life and method as the asset for which the ARO is attached.

The cumulative affect adjustment is offset by a credit to other regulatory credits (Account 407) and a debit to Regulatory assets (Account 182.3)

DESCRIPTION	DEBIT	CREDIT
Cumulative Effect Adjustment - IS Account 435	11,210	
ARO Liability - BS Account 230		11,210
To record accumulated accretion on ARO liability		

The total accretion expense that would have been incurred if the liability was accreted from the time the liability was incurred to date.

The cumulative affect adjustment is offset by a credit to other regulatory credits (Account 407) and a debit to Regulatory assets (Account 182.3)

DESCRIPTION	DEBIT	CREDIT
Accumulated Deprecation- BS Account 108	4,283	
Regulatory Liability - BS Account 254		1,930
Cumulative Effect Adjustment - IS Account 435		2,352
To reclassify existing Cost of Removal		

The COR liability currently reflected on the Balance Sheet must be fully reversed from the reserve.

The cumulative affect adjustment is offset by a credit to other regulatory credits (Account 407) and a debit to Regulatory assets (Account 182.3)

DESCRIPTION	DEBIT	CREDIT
Regulatory Assets - BS Account 182.3	11,290	
Regulatory Credits - IS Account 407		11,290

Because ARO costs qualify for SFAS 71 treatment The cumulative affect adjustment is offset by a credit to other regulatory credits (Account 407) and a debit to Regulatory assets (Account 182.3)

Louisville Gas and Electric Company
ARO Journal Entries
($000's)

DESCRIPTION	Annual Amount DEBIT	Annual Amount CREDIT
JOURNAL ENTRIES REQUIRED AT IMPLEMENTATION		
Long Lived Assets - ARO - *(New Account)*	2,746	
COR Liability Accrued to Date	631	
Regulatory Asset	5,064	
Cumulative effect	5,064	
Regulatory Credits		5,064
Regulatory Liability (New Account)		104
Accumulated Depreciation of ARO Asset - *(New Account)*		861
ARO Liability - *(New Account)*		7,475
	13,503	13,503
To record the Implementation of FAS 143		
Long Lived Assets - ARO - BS Account 317	2,746	
ARO Liability - BS *Account 230*		2,746
To record the initial present value of ARO liability		
Upon implementation of FAS 143, the ARO liability (in current dollars) must be future valued at the anticipated inflation rate. The ARO liability must then be present valued back to when the liability was incurred using risk free rate plus risk premium at the time the liability was incurred.		
The ARO asset is valued at the present value of the liability at the time the liability is incurred.		
Cumulative Effect Adjustment - IS Account 435	861	
Accumulated Depreciation of ARO Asset - *BS Account 108*		861
To record accumulated depreciation on ARO assets		
Assumes the ARO Asset is depreciated over the same life and method as the asset for which the ARO is attached.		
The cumulative affect adjustment is offset by a credit to other regulatory credits (Account 407) and a debit to Regulatory assets (Account 182.3)		
Cumulative Effect Adjustment - IS Account 435	4,729	
ARO Liability - BS Account 230		4,729
To record accumulated accretion on ARO liability		
The total accretion expense that would have been incurred if the liability was accreted from the time the liability was incurred to date.		
The cumulative affect adjustment is offset by a credit to other regulatory credits (Account 407) and a debit to Regulatory assets (Account 182.3)		
Accumulated Deprecation- BS Account 108	631	
Regulatory Liability - BS Account 254		104
Cumulative Effect Adjustment - IS Account 435		527
To reclassify existing Cost of Removal		
The COR liability currently reflected on the Balance Sheet must be fully reversed from the reserve.		
The cumulative affect adjustment is offset by a credit to other regulatory credits (Account 407) and a debit to Regulatory assets (Account 182.3)		
Regulatory Assets - BS Account 182.3	5,064	
Regulatory Credits - IS Account 407		5,064
Because ARO costs qualify for SFAS 71 treatment The cumulative affect adjustment is offset by a credit to other regulatory credits (Account 407) and a debit to Regulatory assets (Account 182.3)		

Louisville Gas and Electric Company
ARO Journal Entries
($000's)

DESCRIPTION	Annual Amounts DEBIT	CREDIT
JOURNAL ENTRIES SUBSEQUENT TO IMPLEMENTATION		
Depreciation Expense - IS Account 403.1	42.35	
Accumulated Depreciation of ARO Asset - *BS Account 108.1*		42.35
To record monthly depreciation expense		
Assumes the ARO Asset is depreciated over the same life and method as the asset for which the ARO is attached.		
Regulatory Asset Account- BS Account 182.3	**42.35**	
Regulatory Credits - IS Account 407		**42.35**
To reverse monthly depreciation to regulatory asset/liability (Utility is I/S Neutral)		
The monthly depreciation expense must be reflected against a Regulatory Asset so that all effects of FAS 143 are Income Statement neutral.		
Accretion Expense - IS Account 411.1	**366.49**	
ARO Liability - *BS Account 230*		**366.49**
To record monthly accretion expense on ARO liability		
The liability at implementation must be accreted to the anticipated cash outlay.		
Regulatory Asset Account- BS Account 182.3	366.49	
Regulatory Credits - IS Account 407		366.49
To reverse monthly accretion expense to regulatory asset/liability (Utility is I/S neutral)		
The monthly depreciation expense must be reflected against a Regulatory Asset so that all effects of FAS 143 are Income Statement neutral.		
Depreciation Expense	xxxx	
Accumulated Depreciation		xxxx
To record monthly depreciation expense on underlying asset to which ARO related		
The underlying asset to which the ARO is attached is already in G/L systems and is shown for illustrative purposes. The original asset must somehow be linked to the ARO asset, the ARO **Liability and the Regulatory Asset / Liability.**		

Kentucky Utilities Company
ARO Journal Entries
($000's)

DESCRIPTION	Annual Amount DEBIT	Annual Amount CREDIT
JOURNAL ENTRIES REQUIRED AT IMPLEMENTATION		
Long Lived Assets - ARO - *(New Account)*	7,299	
COR Liability Accrued to Date	3,852	
Regulatory Asset	6,227	
Cumulative effect	6,227	
Regulatory Credits		6,227
Regulatory Liability (New Account)		1,826
Accumulated Depreciation of ARO Asset - *(New Account)*		1,572
ARO Liability - *(New Account)*		13,780
	23,405	23,405
To record the implementation of FAS 143		

Long Lived Assets - ARO - BS Account 317	7,299	
ARO Liability - BS *Account 230*		7,299
To record the initial present value of ARO liability		

Upon implementation of FAS 143, the ARO liability (in current dollars) must be future valued at the anticipated inflation rate. The ARO liability must then be present valued back to when the liability was incurred using risk free rate plus risk premium at the time the liability was incurred.

The ARO asset is valued at the present value of the liability at the time the liability is incurred.

Cumulative Effect Adjustment - IS Account 435	1,572	
Accumulated Depreciation of ARO Asset - *BS Account 108*		1,572
To record accumulated depreciation on ARO assets		

Assumes the ARO Asset is depreciated over the same life and method as the asset for which the ARO is attached.

The cumulative affect adjustment is offset by a credit to other regulatory credits (Account 407) and a debit to Regulatory assets (Account 182.3)

Cumulative Effect Adjustment - IS Account 435	6,480	
ARO Liability - BS Account 230		6,480
To record accumulated accretion on ARO liability		

The total accretion expense that would have been incurred if the liability was accreted from the time the liability was incurred to date.

The cumulative affect adjustment is offset by a credit to other regulatory credits (Account 407) and a debit to Regulatory assets (Account 182.3)

Accumulated Deprecation- BS Account 108	3,652	
Regulatory Liability - BS Account 254		1,826
Cumulative Effect Adjustment - IS Account 435		1,826
To reclassify existing Cost of Removal		

The COR liability currently reflected on the Balance Sheet must be fully reversed from the reserve.

The cumulative affect adjustment is offset by a credit to other regulatory credits (Account 407) and a debit to Regulatory assets (Account 182.3)

Regulatory Assets - BS Account 182.3	6,227	
Regulatory Credits - IS Account 407		6,227

Because ARO costs qualify for SFAS 71 treatment The cumulative affect adjustment is offset **by a credit to other regulatory credits (Account 407) and a debit to Regulatory assets (Account 182.3)**

Kentucky Utilities Company
ARO Journal Entries
($000's)

DESCRIPTION	Annual Amounts DEBIT	CREDIT
PART II JOURNAL ENTRIES SUBSEQUENT TO IMPLEMENTATION		
Depreciation Expense - IS Account 403.1	188	
Accumulated Depreciation of ARO Asset - *BS Account 108.1*		188
To record monthly depreciation expense		
Assumes the ARO Asset is depreciated over the same life and method as the asset for which the ARO is attached.		
Regulatory Asset Account- BS Account 182.3	188	
Regulatory Credits - IS Account 407		188
To reverse monthly depreciation to regulatory asset/liability (Utility is I/S Neutral)		
The monthly depreciation expense must be reflected against a Regulatory Asset so that all effects of FAS 143 are Income Statement neutral.		
Accretion Expense - IS Account 411.1	786	
ARO Liability - *BS Account 230*		786
To record monthly accretion expense on ARO liability		
The liability at implementation must be accreted to the anticipated cash outlay.		
Regulatory Asset Account- BS Account 182.3	786	
Regulatory Credits - IS Account 407		786
To reverse monthly accretion expense to regulatory asset/liability (Utility is I/S neutral)		
The monthly depreciation expense must be reflected against a Regulatory Asset so that all effects of FAS 143 are Income Statement neutral.		
Depreciation Expense	xxxx	
Accumulated Depreciation		xxxx
To record monthly depreciation expense on underlying asset to which ARO related		
The underlying asset to which the ARO is attached is already in G/L systems and is shown for illustrative purposes. The original asset must somehow be linked to the ARO asset, the ARO Liability and the Regulatory Asset / Liability.		

Table 1a - KY

Kentucky Utilities
Electric Division
Kentucky
Calculation of Cost of Removal in Book Depreciation Reserve as of December 31, 2002 Based Upon Theoretical Depreciation Reserves (By Location and Account) Using Existing Depreciation Parameters

Account No. (a)	Loc. Code	Description (b)	Original Cost 12/31/02 (c)	Total Book Depr Reserve 12/31/02 (j)	Adjustment For Omitted Retirements (k)	Plant Depr Reserve 12/31/02 (l)	Cost of Removal Depr Reserve 12/31/02
		DEPRECIABLE PLANT					
		STEAM PLANT					
		KU Generation-Common					
311.00	5591	Structures and Improvements	805,715.82	373,841.85		337,926.85	35,915.00
316.00	5591	Misc. Power Plant Equipment	1,330,284.07	244,560.51		215,132.51	29,428.00
		Total KU Gen.-Common	2,135,999.89	618,402.36	0.00	553,059.36	65,343.00
		Tyrone Unit 3					
311.60	5603	Structures and Improvements	5,293,882.85	5,722,687.36		4,929,429.36	793,258.00
312.00	5603	Boiler Plant Equipment	8,663,220.42	8,867,763.82		7,824,472.82	1,043,291.00
312.00	5603	Mandated NOX Proj.-2004 Closing	1,502,053.00			0.00	0.00
314.00	5603	Turbogenerator Units	2,649,841.16	3,039,367.81		2,653,065.81	386,302.00
315.00	5603	Accessory Electric Equipment	570,736.22	635,229.41		548,104.41	87,125.00
316.00	5603	Misc. Power Plant Equipment	403,549.14	245,719.29		214,760.29	30,959.00
		Total Tyrone Unit 3	19,083,282.79	18,510,767.89	0.00	16,169,832.69	2,340,935.00
		Tyrone Units 1 & 2					
311.60	5604	Structures and Improvements	589,406.14	676,047.70		566,941.70	109,106.00
312.00	5604	Boiler Plant Equipment	3,549,368.50	4,048,571.36		3,306,109.36	742,462.00
314.00	5604	Turbogenerator Units	1,592,029.04	1,813,795.27		1,478,911.27	334,884.00
315.00	5604	Accessory Electric Equipment	828,016.44	881,009.49		707,589.49	173,420.00
316.00	5604	Misc. Power Plant Equipment	47,552.54	49,787.51		39,804.51	9,983.00
		Total Tyrone Units 1 & 2	6,606,371.66	7,469,211.32	0.00	6,099,356.32	1,369,855.00
		Green River Unit 3					
311.40	5613	Structures and Improvements	2,809,804.71	3,228,465.61		2,945,216.61	283,249.00
312.00	5613	Boiler Plant Equipment	9,061,059.76	8,870,130.27		8,096,688.27	773,442.00
312.00	5613	Mandated NOX Proj.-2004 Closing	1,731,984.00			0.00	0.00
314.00	5613	Turbogenerator Units	2,651,645.58	3,041,437.48		2,755,705.48	285,732.00
315.00	5613	Accessory Electric Equipment	696,352.89	761,113.71		697,346.71	63,767.00
316.00	5613	Misc. Power Plant Equipment	70,833.53	53,321.13		48,341.13	4,980.00
		Total Green River Unit 3	17,021,680.47	15,954,468.20	0.00	14,543,298.20	1,411,170.00
		Green River Unit 4					
311.40	5614	Structures and Improvements	4,099,390.94	3,630,655.71		3,381,760.71	248,895.00
312.00	5614	Boiler Plant Equipment	18,776,499.07	14,845,967.78		13,624,266.78	1,221,701.00
314.00	5614	Turbogenerator Units	8,323,622.30	6,365,139.77		5,843,012.77	522,127.00
315.00	5614	Accessory Electric Equipment	809,269.35	907,190.94		834,325.94	72,865.00
316.00	5614	Misc. Power Plant Equipment	1,961,965.76	1,134,997.25		1,034,887.25	100,110.00
		Total Green River Unit 4	33,970,747.42	26,883,951.46	0.00	24,718,253.46	2,165,698.00
		Green River Units 1&2					
311.40	5615	Structures and Improvements	3,797,160.20	4,226,239.30		3,682,695.30	543,544.00
312.00	5615	Boiler Plant Equipment	12,249,873.99	11,761,983.55		10,164,249.55	1,597,734.00
314.00	5615	Turbogenerator Units	2,762,747.30	2,769,226.60		2,390,366.60	378,860.00
315.00	5615	Accessory Electric Equipment	584,072.29	649,488.39		564,622.39	84,866.00
316.00	5615	Misc. Power Plant Equipment	190,224.48	180,211.55		153,691.55	26,520.00
		Total Green River Units 1&2	19,584,078.26	19,587,149.39	0.00	16,955,625.39	2,631,524.00
		Brown Unit 1					
311.10	5621	Structures and Improvements	4,088,137.49	4,518,000.24		4,179,478.24	338,522.00
312.00	5621	Boiler Plant Equipment	32,815,581.55	19,517,750.44		17,766,421.44	1,751,329.00
312.00	5621	Mandated NOX Proj.-2004 Closing	221,421.00			0.00	0.00
314.00	5621	Turbogenerator Units	4,694,847.01	4,801,992.34		4,372,650.34	429,342.00
315.00	5621	Accessory Electric Equipment	2,663,640.09	2,136,179.18		1,960,528.18	175,651.00
316.00	5621	Misc. Power Plant Equipment	293,859.48	201,466.86		181,882.86	19,584.00
		Total Brown Unit 1	44,777,486.62	31,175,389.07	0.00	28,460,961.07	2;714,428.00

Table 1a - KY

Kentucky Utilities
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Account No. (a)	Loc. Code	Description (b)	Original Cost 12/31/02 (c)	Total Book Depr Reserve 12/31/02 (l)	Adjustment For Omitted Retirements (k)	Plant Depr Reserve 12/31/02 (l)	Cost of Removal Depr Reserve 12/31/02
		Brown Unit 2					
311.10	5622	Structures and Improvements	1,452,821.22	1,685,381.25		1,550,088.25	135,293.00
312.00	5622	Boiler Plant Equipment	26,010,201.59	16,848,811.36		15,229,650.36	1,619,161.00
312.00	5622	Mandated NOX Proj.-2004 Closing	2,237,589.00			0.00	0.00
314.00	5622	Turbogenerator Units	8,729,916.37	6,056,772.92		5,476,396.92	580,376.00
315.00	5622	Accessory Electric Equipment	970,598.10	912,287.58		832,032.58	80,255.00
316.00	5622	Misc. Power Plant Equipment	85,647.82	69,823.47		62,557.47	7,266.00
		Total Brown Unit 2	39,486,772.10	25,573,076.58	0.00	23,150,725.58	2,422,351.00
		Brown Unit 3					
311.10	5623	Structures and Improvements	12,078,731.61	11,558,765.60		10,589,507.60	969,258.00
312.00	5623	Boiler Plant Equipment	71,536,455.78	49,316,382.34		44,368,891.34	4,947,491.00
312.00	5623	Mandated NOX Proj.-2004 Closing	1,305,198.00			0.00	0.00
312.00	5623	Mandated NOX Proj.-2005 Closing	4,004,000.00			0.00	0.00
314.00	5623	Turbogenerator Units	22,985,210.48	13,723,542.56		12,349,015.56	1,374,527.00
315.00	5623	Accessory Electric Equipment	5,076,639.52	4,577,463.36		4,156,038.36	421,425.00
316.00	5623	Misc. Power Plant Equipment	3,695,436.94	1,904,428.84		1,699,247.84	205,181.00
		Total Brown Unit 3	120,681,672.33	81,080,582.70	0.00	73,162,700.70	7,917,882.00
		Pineville Unit 3					
311.50	5643	Structures and Improvements	0.00	0.00		0.00	0.00
312.00	5643	Boiler Plant Equipment	226,832.50	1,782,011.42		1,750,876.42	31,135.00
314.00	5643	Turbogenerator Units	0.00	0.00		0.00	0.00
315.00	5643	Accessory Electric Equipment	0.00	0.00		0.00	0.00
316.00	5643	Misc. Power Plant Equipment	0.00	0.00		0.00	0.00
		Total Pineville Unit 3	226,832.50	1,782,011.42	0.00	1,750,876.42	31,135.00
		Pineville Units 1 & 2					
311.50	5644	Structures and Improvements	0.00	0.00		0.00	0.00
312.00	5644	Boiler Plant Equipment	0.00	254,230.51		254,230.51	0.00
314.00	5644	Turbogenerator Units	0.00	0.00		0.00	0.00
315.00	5644	Accessory Electric Equipment	0.00	0.00		0.00	0.00
316.00	5644	Misc. Power Plant Equipment	0.00	0.00		0.00	0.00
		Total Pineville Units 1 & 2	0.00	254,230.51	0.00	254,230.51	0.00
		Ghent 1 Pollution Control Equip.					
311.30	5650	Structures and Improvements	24,352,142.19	10,966,983.04		10,274,287.04	692,696.00
312.00	5650	Boiler Plant Equipment	86,308,756.05	34,816,239.80		32,375,570.80	2,440,669.00
315.00	5650	Turbogenerator Units	3,016,784.27	1,319,776.32		1,234,173.32	85,603.00
316.00	5650	Accessory Electric Equipment	985,410.01	371,392.72		343,404.72	27,988.00
		Total Ghent 1 Pollution Control Equip.	114,663,092.52	47,474,391.89	0.00	44,227,435.89	3,246,956.00
		Ghent Unit 1					
311.20	5651	Structures and Improvements	16,838,431.28	16,551,200.35		15,670,282.35	880,918.00
312.00	5651	Boiler Plant Equipment	88,268,090.96	58,633,236.77		54,906,380.77	3,726,856.00
312.00	5623	Mandated NOX Proj.-2004 Closing	38,235,757.00			0.00	0.00
312.00	5623	Mandated NOX Proj.-2005 Closing	38,980,000.00			0.00	0.00
314.00	5651	Turbogenerator Units	22,672,866.15	17,547,331.79		16,436,757.79	1,110,574.00
315.00	5651	Accessory Electric Equipment	7,456,587.14	6,385,744.31		6,385,744.31	0.00
316.00	5651	Misc. Power Plant Equipment	1,883,635.89	1,107,233.96		1,031,489.96	75,744.00
		Total Ghent Unit 1		100,224,747.18	0.00	94,430,655.18	5,794,092.00

Table 1a - KY

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Account No. (a)	Loc. Code	Description (b)	Original Cost 12/31/02 (c)	Total Book Depr Reserve 12/31/02 (j)	Adjustment For Omitted Retirements (k)	Plant Depr Reserve 12/31/02 (l)	Cost of Removal Depr Reserve 12/31/02
		Ghent Unit 2					
311.20	5652	Structures and Improvements	16,012,536.37	14,520,990.15		13,763,216.15	757,774.00
312.00	5652	Boiler Plant Equipment	86,733,989.30	58,712,497.52		55,065,177.52	3,647,320.00
312.00	5652	Mandated NOX Proj.-2004 Closing	4,735.00			0.00	0.00
312.00	5652	Mandated NOX Proj.-2005 Closing	3,016,000.00			0.00	0.00
314.00	5652	Turbogenerator Units	28,358,360.55	18,546,227.18		17,401,567.18	1,144,660.00
315.00	5652	Accessory Electric Equipment	10,785,959.50	8,840,614.25		8,840,614.25	0.00
316.00	5652	Misc. Power Plant Equipment	1,478,017.69	1,038,436.36		969,123.36	69,313.00
		Total Ghent Unit 2	146,389,598.41	101,658,765.46	0.00	96,039,698.45	5,619,067.00
		Ghent Unit 3					
311.20	5653	Structures and Improvements	40,539,913.20	29,396,596.88		27,779,408.88	1,617,188.00
312.00	5653	Boiler Plant Equipment	169,648,430.42	102,664,063.36		95,978,667.36	6,685,396.00
312.00	5653	Mandated NOX Proj.-2004 Closing	73,887,596.00			0.00	0.00
312.00	5653	Mandated NOX Proj.-2005 Closing	1,976,000.00			0.00	0.00
314.00	5653	Turbogenerator Units	38,111,389.85	23,633,415.76		22,109,025.76	1,524,390.00
315.00	5653	Accessory Electric Equipment	25,961,221.84	17,808,728.79		17,808,728.79	0.00
316.00	5653	Misc. Power Plant Equipment	3,135,971.64	1,849,696.44		1,720,838.44	128,858.00
		Total Ghent Unit 3	353,260,522.95	175,352,501.24	0.00	165,396,669.24	9,955,832.00
		Ghent Unit 4					
311.20	5654	Structures and Improvements	21,953,259.20	12,923,736.93		12,202,326.93	721,410.00
312.00	5654	Boiler Plant Equipment	168,701,912.41	83,355,028.86		77,875,705.86	5,479,323.00
312.00	5654	Mandated NOX Proj.-2004 Closing	52,148,251.00			0.00	0.00
312.00	5654	Mandated NOX Proj.-2005 Closing	15,424,000.00			0.00	0.00
314.00	5654	Turbogenerator Units	48,190,569.27	26,306,716.71		24,595,210.71	1,711,506.00
315.00	5654	Accessory Electric Equipment	21,869,238.82	12,749,802.99		12,749,802.99	0.00
316.00	5654	Misc. Power Plant Equipment	5,356,692.15	1,998,833.97		1,859,015.97	139,818.00
		Total Ghent Unit 4	333,643,922.85	137,334,119.46	0.00	129,282,062.46	8,052,057.00
		Ghent 4 Rail Cars					
312.20	5659	Boiler Plant Equipment	7,647,232.19	3,920,826.86		3,722,898.86	197,928.00
		Total Ghent 4 Rail Cars	7,647,232.19	3,920,826.86	0.00	3,722,898.86	197,928.00
		Total Steam Production	1,333,494,917.96	794,854,592.77	0.00	738,918,339.77	55,936,253.00
		HYDRAULIC PLANT					
		Dix Dam					
330.10	5691	Land Rights	879,311.47	879,311.47		879,311.47	0.00
331.10	5691	Structures and Improvements	429,524.71	328,160.22		301,863.22	26,297.00
332.10	5691	Reservoirs, Dams and Waterways	7,818,030.36	5,639,672.93		5,129,939.93	509,733.00
333.10	5691	Waterwheel, Turbines and Generators	418,543.74	526,528.02		496,732.02	29,796.00
334.10	5691	Accessory Electric Equipment	85,383.13	69,663.35		63,571.35	6,092.00
335.10	5691	Misc. Power Plant Equipment	97,031.59	50,788.41		46,453.41	4,335.00
336.10	5691	Roads, Railroads and Bridges	46,976.12	41,111.69		37,545.69	3,566.00
		Total Dix Dam	9,774,801.12	7,535,236.10	0.00	6,955,417.10	579,819.00
		Lock #7					
330.10	5692	Land Rights	0.00			0.00	0.00
331.20	5692	Structures and Improvements	87,902.49	69,837.66		49,951.66	19,886.00
332.20	5692	Reservoirs, Dams and Waterways	324,145.88	288,220.44		195,327.44	92,893.00
333.20	5692	Waterwheel, Turbines and Generators	114,085.49	126,064.47		92,780.47	33,284.00
334.20	5692	Accessory Electric Equipment	264,485.91	245,974.54		172,287.54	73,687.00
335.20	5692	Misc. Power Plant Equipment	66,094.89	57,509.70		39,348.70	18,161.00
336.20	5692	Roads, Railroads and Bridges	1,169.79	1,061.33		718.33	343.00
		Total Lock #7	837,884.45	788,668.13	0.00	550,414.13	238,254.00
		Total Hydraulic Plant	10,612,685.57	8,323,904.23	0.00	7,505,831.23	818,073.00

Table 1a - KY

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Account No. (a)	Loc. Code	Description (b)	Original Cost 12/31/02 (c)	Total Book Depr Reserve 12/31/02 (j)	Adjustment For Omitted Retirements (k)	Plant Depr Reserve 12/31/02 (l)	Cost of Removal Depr Reserve 12/31/02
		OTHER PRODUCTION PLANT					
		Paddy's Run GT 13					
341.00	0432	Structures and Improvements	1,910,327.76	92,928.55		92,928.55	0.00
342.00	0432	Fuel Holders, Producers and Access.	1,975,977.95	111,401.17		111,401.17	0.00
343.00	0432	Prime Movers	17,355,293.47	808,034.94		808,034.94	0.00
344.00	0432	Generators	5,185,836.11	307,414.14		307,414.14	0.00
345.00	0432	Accessory Electric Equipment	2,458,320.01	125,405.92		125,405.92	0.00
346.00	0432	Misc. Power Plant Equipment	1,089,550.03	53,681.91		53,681.91	0.00
		Total Paddy's Run GT 13	29,973,105.33	1,498,866.63	0.00	1,498,866.63	0.00
		Trimble Co 5					
341.00	0470	Structures and Improvements	3,566,217.06	56,544.29		56,544.29	0.00
342.00	0470	Fuel Holders, Producers and Access.	237,747.79	4,376.02		4,376.02	0.00
343.00	0470	Prime Movers	29,842,502.10	452,882.82		452,882.82	0.00
344.00	0470	Generators	3,734,423.83	72,278.13		72,278.13	0.00
345.00	0470	Accessory Electric Equipment	1,664,234.64	27,740.69		27,740.69	0.00
		Total Trimble Co 5	39,045,125.42	613,821.94	0.00	613,821.94	0.00
		Trimble Co 6					
341.00	0471	Structures and Improvements	3,564,353.91	56,515.17		56,515.17	0.00
342.00	0471	Fuel Holders, Producers and Access.	237,623.60	4,373.11		4,373.11	0.00
343.00	0471	Prime Movers	29,826,880.91	452,646.01		452,646.01	0.00
344.00	0471	Generators	3,732,468.71	72,240.28		42,240.28	30,000.00
345.00	0471	Accessory Electric Equipment	1,663,365.15	27,726.13		27,726.13	0.00
		Total Trimble Co 6	39,024,692.28	613,500.69	0.00	583,500.69	30,000.00
		Trimble Co Pipeline					
342.00	0473	Trimble Co Pipeline	4,474,853.28	95,855.07		95,855.07	0.00
		Trimble Co Pipeline	4,474,853.28	95,855.07	0.00	95,855.07	0.00
		Brown 5					
341.00	5635	Structures and Improvements	755,148.65	37,043.69		37,043.69	0.00
342.00	5635	Fuel Holders, Producers and Access.	727,929.28	41,384.06		41,384.06	0.00
343.00	5635	Prime Movers	12,440,942.32	584,099.27		584,099.27	0.00
344.00	5635	Generators	2,831,528.33	169,269.40		169,269.40	0.00
345.00	5635	Accessory Electric Equipment	2,265,166.84	116,618.79		116,618.79	0.00
346.00	5635	Misc. Power Plant Equipment	2,085,163.17	103,598.68		103,598.68	0.00
		Total Brown 5	21,105,878.59	1,052,013.88	0.00	1,052,013.88	0.00
		Brown 6					
341.00	5636	Structures and Improvements	133,678.33	15,683.87		15,683.87	0.00
342.00	5636	Fuel Holders, Producers and Access.	146,514.66	19,731.26		19,731.26	0.00
343.00	5636	Prime Movers	31,591,711.55	3,471,602.03		3,471,602.03	0.00
344.00	5636	Generators	3,712,619.52	526,458.34		526,458.34	0.00
345.00	5636	Accessory Electric Equipment	1,354,816.11	165,517.84		165,517.84	0.00
346.00	5636	Misc. Power Plant Equipment	18,003.82	1,852.51		1,852.51	0.00
		Total Brown 6	36,957,343.99	4,200,845.85	0.00	4,200,845.85	0.00
		Brown 7					
341.00	5637	Structures and Improvements	456,353.77	54,782.80		54,782.80	0.00
342.00	5637	Fuel Holders, Producers and Access.	145,745.15	18,790.39		18,790.39	0.00
343.00	5637	Prime Movers	39,071,447.54	3,762,389.64		3,762,389.64	0.00
344.00	5637	Generators	3,722,768.46	506,168.50		506,168.50	0.00
345.00	5637	Accessory Electric Equipment	1,347,700.35	157,809.63		157,809.63	0.00
346.00	5637	Misc. Power Plant Equipment	15,776.54	1,774.61		1,774.61	0.00
		Total Brown 7	44,791,811.81	4,501,715.56	0.00	4,501,715.56	0.00

Table 1a - KY

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Account No. (a)	Loc. Code	Description (b)	Original Cost 12/31/02 (c)	Total Book Depr Reserve 12/31/02 (j)	Adjustment For Omitted Retirements (k)	Plant Depr Reserve 12/31/02 (l)	Cost of Removal Depr Reserve 12/31/02
		Brown 8					
341.00	5638	Structures and Improvements	2,012,654.95	551,147.81		551,147.81	0.00
342.00	5638	Fuel Holders, Producers and Access.	19,612.88	6,197.13		6,197.13	0.00
343.00	5638	Prime Movers	18,625,319.58	4,649,763.68		4,649,763.68	0.00
344.00	5638	Generators	4,953,960.72	1,657,115.05		1,657,115.05	0.00
345.00	5638	Accessory Electric Equipment	1,797,053.82	516,223.20		516,223.20	0.00
346.00	5638	Misc. Power Plant Equipment	230,068.72	63,080.90		63,080.90	0.00
		Total Brown 8	27,638,670.67	7,443,527.78	0.00	7,443,527.78	0.00
		Brown 9					
341.00	5639	Structures and Improvements	4,641,054.88	1,283,383.52		1,283,383.52	0.00
342.00	5639	Fuel Holders, Producers and Access.	1,943,454.44	587,787.17		587,787.17	0.00
343.00	5639	Prime Movers	20,674,801.66	5,251,127.97		5,251,127.97	0.00
344.00	5639	Generators	5,452,040.97	1,849,282.53		1,849,282.53	0.00
345.00	5639	Accessory Electric Equipment	3,226,186.26	926,881.86		926,881.86	0.00
346.00	5639	Misc. Power Plant Equipment	760,255.37	208,250.52		208,250.52	0.00
		Total Brown 9	36,697,793.56	10,106,713.57	0.00	10,106,713.57	0.00
		Brown 10					
341.00	5640	Structures and Improvements	1,865,718.20	450,116.53		450,116.53	0.00
342.00	5640	Fuel Holders, Producers and Access.	31,737.96	8,861.24		8,861.24	0.00
343.00	5640	Prime Movers	18,800,096.69	4,229,904.20		4,229,904.20	0.00
344.00	5640	Generators	4,944,422.71	1,447,725.28		1,447,725.28	0.00
345.00	5640	Accessory Electric Equipment	1,804,419.47	455,008.19		455,008.19	0.00
346.00	5640	Misc. Power Plant Equipment	241,523.31	54,067.02		54,067.02	0.00
		Total Brown 10	27,687,918.34	6,645,682.47	0.00	6,645,682.47	0.00
		Brown 11					
341.00	5641	Structures and Improvements	1,802,595.65	381,497.12		381,497.12	0.00
342.00	5641	Fuel Holders, Producers and Access.	52,429.84	12,597.47		12,597.47	0.00
343.00	5641	Prime Movers	33,050,028.28	5,018,851.36		5,018,851.36	0.00
344.00	5641	Generators	5,187,040.30	1,365,544.57		1,365,544.57	0.00
345.00	5641	Accessory Electric Equipment	916,326.28	207,761.39		207,761.39	0.00
346.00	5641	Misc. Power Plant Equipment	204,854.53	39,269.61		39,269.61	0.00
		Total Brown 11	41,213,274.88	7,025,521.52	0.00	7,025,521.52	0.00
		Brown 9 Pipeline					
340.10	5645	Land Rights	176,409.31	49,181.12		49,181.12	0.00
342.00	5645	Fuel Holders, Producers and Access	8,151,131.81	2,181,651.65		2,181,651.65	0.00
		Total Brown 9 Pipeline	8,327,541.12	2,230,832.77	0.00	2,230,832.77	0.00
		Hafeling					
341.00	5696	Structures and Improvements	434,853.46	109,355.00		109,355.00	0.00
342.00	5696	Fuel Holders, Producers and Access.	181,132.61	160,069.45		160,069.45	0.00
344.00	5696	Generators	4,023,002.37	3,495,007.49		3,495,007.49	0.00
345.00	5696	Accessory Electric Equipment	621,206.80	492,390.44		492,390.44	0.00
346.00	5696	Misc. Power Plant Equipment	35,805.20	27,184.63		27,184.63	0.00
		Total Hafeling	23,432,497.79	4,284,007.02	0.00	4,284,007.02	0.00
		Total Other Production Plant	380,370,507.06	50,312,904.75	0.00	50,282,904.75	30,000.00
		Total Production Plant	1,724,478,110.59	853,491,401.75	0.00	796,707,075.75	56,784,326.00
		TRANSMISSION PLANT					
350.10		Land Rights	22,991,433.46	11,658,723.90		11,658,723.90	0.00
		Structures and Improvements					
352.10		Struct. and Improve. - Non Sys. Control/Com.	6,426,546.76	2,832,052.15		1,983,470.72	848,581.43
352.20		Struct. and Improve. - Sys. Control/Com.	1,166,434.25	711,936.94	17,975.03	586,774.60	107,187.31
		Total Account 352	7,592,981.01		17,975.03	2,570,245.32	955,768.74

Table 1a - KY

Kentucky Utilities
Electric Division
Kentucky
Calculation of Cost of Removal In Book Depreciation Reserve as of December 31, 2002 Based Upon Theoretical Depreciation Reserves (By Location and Account) Using Existing Depreciation Parameters

Account No. (a)	Loc. Code	Description (b)	Original Cost 12/31/02 (c)	Total Book Depr Reserve 12/31/02 (j)	Adjustment For Omitted Retirements (k)	Plant Depr Reserve 12/31/02 (l)	Cost of Removal Depr Reserve 12/31/02
		Station Equipment					
353.10		Station Equipment - Non Sys. Control/Com.	146,527,337.37	50,453,773.27		45,266,416.75	5,187,356.52
353.20		Station Equip - Sys.Control/Com. (Microwave)	14,284,914.20	8,038,391.66		7,295,042.92	743,348.74
		Total Account 353	160,812,251.57		0.00	52,561,459.67	5,930,705.26
354.00		Towers and Fixtures	60,533,459.11	35,842,997.16		11,870,207.08	23,972,790.08
355.00		Poles and Fixtures	74,915,940.37	39,080,978.14		17,254,044.30	21,826,933.84
356.00		Overhead Conductors and Devices	122,030,093.52	80,292,060.35		50,843,072.07	29,448,988.28
357.00		Underground Conduit	435,926.80	87,891.34		79,267.50	8,623.84
358.00		Underground Conductors and Devices	1,114,761.90	610,385.26		585,756.22	24,629.04
		Total Transmission Plant	588,247,665.85	229,609,190.17	17,975.03	147,422,776.06	82,168,439.08
		DISTRIBUTION PLANT					
360.10		Land Rights	1,423,182.13	871,665.37		871,665.37	0.00
361.00		Structures and Improvements	3,798,329.41	1,297,363.29		1,100,515.13	196,848.16
362.00		Station Equipment	92,514,069.32	26,913,724.72		21,992,348.35	4,921,376.37
364.00		Poles, Towers and Fixtures	167,558,546.62	71,525,016.94		47,259,930.85	24,265,086.09
365.00		Overhead Conductors and Devices	160,511,631.53	79,079,691.18		42,030,013.30	37,049,677.88
366.00		Underground Conduit	1,551,966.69	790,660.29		730,114.37	60,545.92
367.00		Underground Conductors and Devices	49,804,065.28	11,589,403.43		10,870,627.02	718,776.41
368.00		Line Transformers	209,706,230.76	66,818,337.52		55,671,009.35	11,147,328.17
369.00		Services	81,660,930.54	46,743,901.54		34,607,411.07	12,136,490.47
370.00		Meters	61,133,035.49	17,892,318.35	1,456,792.77	13,832,427.00	2,603,098.58
371.00		Installations on customers' Premises	18,270,303.32	6,925,709.76		6,925,709.76	0.00
373.00		Street Lighting and Signal Systems	45,406,623.49	13,863,494.93		10,782,787.90	3,080,707.03
		Total Distribution Plant	893,357,914.56	344,311,287.31	1,456,792.77	246,674,559.46	96,179,935.08
		GENERAL PLANT					
		Structures and Improvements					
390.10		Struct. And Improve. To Owned Property	28,987,368.24	10,718,145.14		10,718,145.14	0.00
390.20		Improvements to Leased Property	694,489.17	427,336.62		427,336.62	0.00
		Total Account 390	29,681,857.41		0.00	11,145,481.77	0.00
		Office Furniture and Equipment					
391.10		Office Equipment	6,168,471.98	2,154,796.89		2,154,796.89	0.00
391.30		Cash Processing Equipment	369,383.94	250,365.99		250,365.99	0.00
		Total Account 391	6,537,855.92		0.00	2,405,162.88	0.00
393.00		Stores Equipment	571,858.05	347,614.14		347,614.14	0.00
394.00		Tools, Shop and Garage Equipment	3,700,720.83	1,499,979.76		1,499,979.76	0.00
395.00		Laboratory Equipment	3,306,885.77	1,752,921.21		1,752,921.21	0.00
396.00		Power Operated Equipment	200,677.14	126,436.76		126,436.76	0.00
		Communication Equipment					
397.10		Carrier Communication Equipment	3,093,194.70	1,276,444.53		1,276,444.53	0.00
397.20		Remote Control Communication Equipment	3,889,910.58	1,237,153.86		1,237,153.86	0.00
397.30		Mobile Communication Equipment	4,579,895.62	1,132,687.81		1,132,687.81	0.00
		Total Account 397	11,563,000.90		0.00	3,646,286.21	0.00
398.00		Miscellaneous Equipment	457,348.94	213,335.55		213,335.55	0.00
		Total General Plant	56,020,204.96	47,579,179.53	0.00	21,137,218.27	0.00
		Sub-Total Depreciable Plant	3,262,103,895.96	1,474,991,058.76	1,474,767.80	1,211,941,629.54	235,132,700.16
		Other Plant (Not Studied)					
391.20		Non PC Computer Equipment	9,611,731.44	3,963,686.38		3,963,686.38	0.00
391.40		Personal Computers	9,814,322.00	8,735,674.86		8,735,674.86	0.00
392.00		Transportation Equipment - Cars & Trucks	23,749,238.51	13,742,600.02		13,742,600.02	0.00
		Total Other Plant (Not Studied)	43,175,291.95	0.00	0.00	26,441,961.26	
		Total Depreciable Plant	3,305,279,187.91	1,474,991,058.76	1,474,767.80	1,238,383,590.80	235,132,700.16

Table 1a - KY

Kentucky Utilities
Electric Division
Kentucky
Calculation of Cost of Removal in Book Depreciation Reserve as of December 31, 2002 Based Upon Theoretical Depreciation Reserves (By Location and Account) Using Existing Depreciation Parameters

Account No. (a)	Loc. Code	Description (b)	Original Cost 12/31/02 (c)	Total Book Depr Reserve 12/31/02 (j)	Adjustment For Omitted Retirements (k)	Plant Depr Reserve 12/31/02 (l)	Cost of Removal Depr Reserve 12/31/02
		NON-DEPRECIABLE PLANT					
		INTANGIBLE PLANT					
301.00		Organization	44,455.58	0.00		0.00	
302.00		Franchises and Consents	81,350.32	0.00		0.00	
303.00		Miscellaneous Intangible Plant	17,297,387.08	0.00		0.00	
		Total Intangible Plant	17,423,192.98	0.00	0.00	0.00	
		LAND & LAND RIGHTS					
310.20		Production Land	10,478,524.55	0.00		0.00	
330.20		Hydraulic Plant	13,479.47	0.00		0.00	
340.20		Other Production Land	98,602.74	0.00		0.00	
350.20		Transmission Land	1,162,528.04	0.00		0.00	
360.20		Distribution Land	1,584,825.82	0.00		0.00	
389.20		Land	2,826,347.43	0.00		0.00	
		Total Land	16,164,308.05	0.00	0.00	0.00	
		Total Non-Depreciable Plant	33,587,501.03	0.00	0.00	0.00	
		Total Electric Plant in Service	3,338,866,688.94	1,474,991,058.76	1,474,767.80	1,238,383,590.80	

(1) Life Span Method Utilized. Interim Retirement Rate. Service Lives Vary.

Summary		% of Adj'd Resv Depr Reserve
Total Book Depr Reserve 12-31-02	$1,474,991,058.76	
Adjustment for Omitted Retirements	1,474,767.80	
Adjusted Book Depr Reserve 12-31-02	1,473,516,290.96	
Plant & Gross Salvage Depr Reserve 12-31-02	1,238,383,590.80	84.0%
Cost of Removal Depr Reserve 12-31-02	235,132,700.16	16.0%

Table 1a - VA

Kentucky Utilities
Electric Division
Virginia
Calculation of Cost of Removal in Book Depreciation Reserve as of December 31, 2002 Based Upon Theoretical Depreciation Reserves (By Location and Account) Using Existing Depreciation Parameters

Account No. (a)	Description (b)	Original Cost 12/31/02 (c)	Total Book Depr Reserve 12/31/02 (g)	Plant Depr Reserve 12/31/02	Cost of Removal Depr Reserve 12/31/02
	DEPRECIABLE PLANT				
	TRANSMISSION PLANT				
350.10	Land Rights	1,782,030.88	1,282,804.80	1,282,804.80	0.00
	Structures and Improvements				
352.10	Struct. and Improve. - Non Sys. Control/Com.	1,050,280.78	501,590.05	360,507.47	141,082.58
352.20	Struct. and Improve. - Sys. Control/Com.	0.00	0.00	0.00	0.00
	Total Account 352	1,050,280.78		360,507.47	141,082.58
	Station Equipment				
353.10	Station Equipment - Non Sys. Control/Com.	13,943,172.45	4,808,386.94	4,346,731.70	461,655.24
353.20	Station Equip - Sys.Control/Com. (Microwave)	0.00	0.00	0.00	0.00
	Total Account 353	13,943,172.45		4,346,731.70	461,655.24
354.00	Towers and Fixtures	6,739,096.01	3,343,877.02	1,244,469.45	2,099,407.57
355.00	Poles and Fixtures	5,246,663.42	2,671,893.76	1,266,261.97	1,405,631.79
356.00	Overhead Conductors and Devices	11,605,472.16	7,164,742.76	4,681,186.31	2,483,556.45
357.00	Underground Conduit	0.00	0.00	0.00	0.00
358.00	Underground Conductors and Devices	0.00	0.00	0.00	0.00
	Total Transmission Plant	40,366,715.70	19,773,295.33	13,181,961.70	6,591,333.63
	DISTRIBUTION PLANT				
360.10	Land Rights	83,580.13	49,087.98	49,087.98	0.00
361.00	Structures and Improvements	367,467.51	138,922.33	120,242.43	18,679.90
362.00	Station Equipment	6,294,362.38	1,857,713.58	1,556,161.58	301,552.00
364.00	Poles, Towers and Fixtures	12,133,206.90	6,062,010.91	4,236,660.23	1,825,350.68
365.00	Overhead Conductors and Devices	12,306,434.76	6,905,462.62	4,037,289.81	2,868,172.81
366.00	Underground Conduit	0.00	0.00	0.00	0.00
367.00	Underground Conductors and Devices	519,618.44	161,218.31	152,286.52	8,931.79
368.00	Line Transformers	12,035,778.33	5,011,031.05	4,268,982.75	742,048.30
369.00	Services	4,905,735.94	3,410,040.37	2,622,607.31	787,433.06
370.00	Meters	3,616,919.29	1,389,229.45	1,209,680.65	179,548.80
371.00	Installations on customers' Premises	867,302.80	437,931.20	437,931.20	0.00
373.00	Street Lighting and Signal Systems	1,229,044.76	489,084.71	392,844.17	96,240.54
	Total Distribution Plant	54,359,451.24	25,911,732.50	19,083,774.62	6,827,957.88
	GENERAL PLANT				
	Structures and Improvements				
390.10	Struct. And Improve. To Owned Property	643,848.85	381,131.81	381,131.81	0.00
390.20	Improvements to Leased Property	75,980.87	65,901.46	65,901.46	0.00
	Total Account 390	719,829.72		447,033.26	0.00
	Office Furniture and Equipment				
391.10	Office Equipment	39,094.49	31,967.61	31,967.61	0.00
391.30	Cash Processing Equipment	0.00	0.00	0.00	0.00
	Total Account 391	39,094.49		31,967.61	0.00

Table 1a - VA

Kentucky Utilities
Electric Division
Virginia
Calculation of Cost of Removal in Book Depreciation Reserve as of December 31, 2002 Based Upon Theoretical Depreciation Reserves (By Location and Account) Using Existing Depreciation Parameters

Account No. (a)	Description (b)	Original Cost 12/31/02 (c)	Total Book Depr Reserve 12/31/02 (g)	Plant Depr Reserve 12/31/02	Cost of Removal Depr Reserve 12/31/02
393.00	Stores Equipment	8,103.30	5,283.48	5,283.48	0.00
394.00	Tools, Shop and Garage Equipment	275,731.08	69,256.48	69,256.48	0.00
395.00	Laboratory Equipment	37,683.18	27,624.58	27,624.58	0.00
396.00	Power Operated Equipment	0.00	0.00	0.00	0.00
	Communication Equipment				
397.10	Carrier Communication Equipment	153,447.99	150,248.86	150,248.86	0.00
397.20	Remote Control Communication Equipment	160,272.74	72,452.57	72,452.57	0.00
397.30	Mobile Communication Equipment	240,853.23	58,275.04	58,275.04	0.00
	Total Account 397	554,573.96		280,976.47	0.00
398.00	Miscellaneous Equipment	16,363.42	11,025.57	11,025.57	0.00
	Total General Plant	1,651,379.15	1,752,006.96	873,167.45	0.00
	Sub-Total Depreciable Plant	96,377,546.09	47,437,034.79	33,138,903.77	13,419,291.51
	Other Plant (Not Studied)				
391.20	Non PC Computer Equipment	0.00	0.00	0.00	
391.40	Personal Computers	0.00	0.00	0.00	
392.00	Transportation Equipment - Cars & Trucks	1,315,837.37	878,839.51	878,839.51	
	Total Other Plant (Not Studied)	1,315,837.37	0.00	878,839.51	0.00
	Total Depreciable Plant	97,693,383.46	47,437,034.79	34,017,743.28	13,419,291.51
	NON-DEPRECIABLE PLANT				
	INTANGIBLE PLANT				
301.00	Organization	5,338.69	0.00		
302.00	Franchises and Consents	0.00	0.00		
303.00	Miscellaneous Intangible Plant	0.00	0.00		
	Total Intangible Plant	5,338.69	0.00	0.00	0.00
	LAND & LAND RIGHTS				
310.20	Production Land	0.00	0.00		
330.20	Hydraulic Plant	0.00	0.00		
340.20	Other Production Land	0.00	0.00		
350.20	Transmission Land	68,167.96	0.00		
360.20	Distribution Land	96,439.08	0.00		
389.20	Land	91,571.48	0.00		
	Total Land	256,178.52	0.00	0.00	0.00
	Total Non-Depreciable Plant	261,517.21	0.00	0.00	0.00
	Total Electric Plant In Service	97,954,900.67	47,437,034.79	34,017,743.28	13,419,291.51

Table 1a - VA

Kentucky Utilities
Electric Division
Virginia
Calculation of Cost of Removal in Book Depreciation Reserve as of December 31, 2002 Based Upon Theoretical Depreciation Reserves (By Location and Account) Using Existing Depreciation Parameters

Account No. (a)	Description (b)	Original Cost 12/31/02 (c)	Total Book Depr Reserve 12/31/02 (g) % of Adj'd Resv Depr Reserve	Plant Depr Reserve 12/31/02	Cost of Removal Depr Reserve 12/31/02
	Summary				
	Total Book Depr Reserve 12-31-02	$47,437,034.79			
	Adjustment for Omitted Retirements	0.00			
	Adjusted Book Depr Reserve 12-31-02	47,437,034.79			
	Plant & Gross Salvage Depr Reserve 12-31-02	34,017,743.28	71.7%		
	Cost of Removal Depr Reserve 12-31-02	13,419,291.51	28.3%		

Louisville Gas and Electric
Electric Division

Calculation of Cost of Removal in Book Depreciation Reserve as of December 31, 2002 Based Upon Theoretical Depreciation Reserves (By Location and Account) Using Existing Depreciation Parameters

Account No. (a)	Description (d)	Cost 12/31/02 (e)	Total Book Depr Reserve 12/31/02 (f)	Cost of Removal Depr Reserve 12/31/02	Adjusted Book Reserve-w/o COR 12/31/2002
	DEPRECIABLE PLANT				
	STEAM PRODUCTION PLANT				
	Cane Run Locomotive & Rail Cars				
312.00	Boiler Plant Equipment	51,549.42	49,217.02	3,348.00	
312.00	Boiler Plant Equipment	1,501,772.81	767,268.58	49,375.00	
	Total Cane Run Locomotive & Rail Cars	1,553,322.23	816,485.60	52,723.00	763,762.60
	Cane Run Unit 1				
311.00	Structures and Improvements	4,182,197.33	5,007,364.88	307,040.00	
312.00	Boiler Plant Equipment	1,053,742.53	1,212,428.34	75,031.00	
314.00	Turbogenerator Units	106,008.55	135,990.09	7,959.00	
315.00	Accessory Electric Equipment	1,891,012.53	2,361,744.12	141,923.00	
316.00	Misc. Power Plant Equipment	151,638.76	183,908.16	8,962.00	
	Total Cane Run Unit 1	7,384,599.70	8,901,435.58	540,915.00	8,360,520.58
	Cane Run Unit 2				
311.00	Structures and Improvements	2,102,941.66	2,104,456.36	152,621.00	
312.00	Boiler Plant Equipment	132,836.82	133,304.91	9,770.00	
314.00	Turbogenerator Units	19,998.97	20,838.93	1,493.00	
315.00	Accessory Electric Equipment	1,277,223.20	1,340,996.08	95,322.00	
	Total Cane Run Unit 2	3,533,000.65	3,599,596.28	259,206.00	3,340,390.28
	Cane Run Unit 3				
311.00	Structures and Improvements	3,532,140.77	5,863,328.73	252,855.00	
312.00	Boiler Plant Equipment	716,616.30	1,119,078.61	48,495.00	
314.00	Turbogenerator Units	581,177.52	1,030,902.17	42,526.00	
315.00	Accessory Electric Equipment	767,324.52	1,326,714.57	56,033.00	
316.00	Misc. Power Plant Equipment	11,664.48	20,567.80	738.00	
	Total Cane Run Unit 3	5,608,923.59	9,360,591.88	400,647.00	8,959,944.88
	Cane Run Unit 4				
311.00	Structures and Improvements	3,547,227.06	3,145,648.04	230,175.00	
312.00	Boiler Plant Equipment	25,980,016.48	14,936,101.51	1,059,047.00	
312.00	Mandated NOX Proj.-2004 Closing	2,442,926.00		0.00	
314.00	Turbogenerator Units	8,432,342.78	6,415,903.06	449,834.00	
315.00	Accessory Electric Equipment	5,490,677.18	2,589,321.48	182,569.00	
316.00	Misc. Power Plant Equipment	54,253.32	17,147.80	1,110.00	
	Total Cane Run Unit 4	45,947,442.82	27,104,121.89	1,922,735.00	25,181,386.89
	Cane Run Unit 4 Scrubber				
311.00	Structures and Improvements	760,360.00	1,142,221.25	40,775.00	
312.00	Boiler Plant Equipment	16,701,761.03	19,987,932.17	710,292.00	
315.00	Accessory Electric Equipment	987,949.29	1,066,985.23	55,200.00	
316.00	Misc. Power Plant Equipment	6,464.30	6,464.30	375.00	
	Total Cane Run Unit 4 Scrubber	18,456,534.62	22,203,602.95	806,642.00	21,396,960.95
	Cane Run Unit 5				
311.00	Structures and Improvements	5,416,846.93	4,223,751.15	319,923.00	
312.00	Boiler Plant Equipment	21,717,140.89	11,680,384.07	862,365.00	
312.00	Mandated NOX Proj.-2004 Closing	2,318,975.00		0.00	
314.00	Turbogenerator Units	6,985,593.95	5,632,062.00	409,643.00	
315.00	Accessory Electric Equipment	6,846,848.21	3,094,934.16	225,458.00	
316.00	Misc. Power Plant Equipment	42,867.49	7,894.99	537.00	
	Total Cane Run Unit 5	43,328,272.47	24,639,026.36	1,817,926.00	22,821,100.36
	Cane Run Unit 5 Scrubber				
311.00	Structures and Improvements	1,696,435.28	1,705,086.49	85,459.00	
312.00	Boiler Plant Equipment	27,928,602.90	25,440,779.02	1,246,622.00	
315.00	Accessory Electric Equipment	2,173,037.73	2,390,465.99	115,499.00	

Louisville Gas and Electric
Electric Division

Calculation of Cost of Removal in Book Depreciation Reserve as of December 31, 2002 Based Upon Theoretical Depreciation Reserves (By Location and Account) Using Existing Depreciation Parameters

Account No. (a)	Description (d)	Cost 12/31/02 (e)	Total Book Depr Reserve 12/31/02 (f)	Cost of Removal Depr Reserve 12/31/02	Adjusted Book Reserve-w/o COR 12/31/2002
316.00	Misc. Power Plant Equipment	47,299.47	60,158.06	2,590.00	
	Total Cane Run Unit 5 Scrubber	31,645,375.38	29,596,489.56	1,450,170.00	28,146,319.56
	Cane Run Unit 6				
311.00	Structures and Improvements	18,149,961.41	11,310,161.61	915,740.00	
312.00	Boiler Plant Equipment	35,613,831.57	18,613,062.65	1,474,838.00	
312.00	Mandated NOX Proj.-2004 Closing	384,664.00		0.00	
314.00	Turbogenerator Units	11,274,211.57	8,027,114.38	626,983.00	
315.00	Accessory Electric Equipment	8,173,345.07	3,909,387.88	306,596.00	
316.00	Misc. Power Plant Equipment	1,806,951.04	915,533.28	64,548.00	
	Total Cane Run Unit 6	75,402,964.76	42,775,259.80	3,388,705.00	39,386,554.80
	Cane Run Unit 6 Scrubber				
311.00	Structures and Improvements	1,859,591.50	1,559,237.99	85,926.00	
312.00	Boiler Plant Equipment	30,524,761.84	22,372,713.66	1,198,527.00	
315.00	Accessory Electric Equipment	2,124,667.29	2,144,382.93	113,141.00	
316.00	Misc. Power Plant Equipment	31,568.91	38,278.10	1,785.00	
	Total Cane Run Unit 6 Scrubber	34,540,589.54	26,114,612.68	1,399,379.00	24,715,233.68
	Mill Creek Locomotive & Rails Cars				
312.00	Boiler Plant Equipment	613,424.43	558,573.13	30,205.00	
312.00	Boiler Plant Equipment	3,631,645.61	1,862,746.59	93,830.00	
	Total Mill Creek Locomotive & Rails Cars	4,245,070.04	2,421,319.72	124,035.00	2,297,284.72
	Mill Creek Unit 1				
311.00	Structures and Improvements	18,350,957.82	15,111,640.28	937,617.00	
312.00	Boiler Plant Equipment	40,579,264.08	25,156,522.44	1,544,604.00	
312.00	Mandated NOX Proj.-2004 Closing	298,528.00		0.00	
312.00	Mandated NOX Proj.-2005 Closing	250,000.00		0.00	
314.00	Turbogenerator Units	13,449,713.81	10,984,999.07	653,059.00	
315.00	Accessory Electric Equipment	14,520,069.59	6,128,517.94	368,445.00	
316.00	Misc. Power Plant Equipment	654,992.48	458,697.92	23,744.00	
	Total Mill Creek Unit 1	88,103,525.78	57,840,377.64	3,527,469.00	54,312,908.64
	Mill Creek Unit 1 Scrubber				
311.00	Structures and Improvements	1,697,743.03	1,217,072.74	64,460.00	
312.00	Boiler Plant Equipment	33,874,404.57	21,426,853.04	1,107,154.00	
315.00	Accessory Electric Equipment	5,541,694.53	4,273,045.26	218,367.00	
	Total Mill Creek Unit 1 Scrubber	41,113,842.13	26,916,971.04	1,389,981.00	25,526,990.04
	Mill Creek Unit 2				
311.00	Structures and Improvements	10,703,506.13	8,178,641.31	494,660.00	
312.00	Boiler Plant Equipment	33,397,635.49	17,698,958.31	1,054,317.00	
312.00	Mandated NOX Proj.-2004 Closing	243,288.00		0.00	
312.00	Mandated NOX Proj.-2005 Closing	250.00		0.00	
314.00	Turbogenerator Units	14,801,053.25	10,895,295.62	631,471.00	
315.00	Accessory Electric Equipment	7,420,343.06	4,450,450.07	261,234.00	
316.00	Misc. Power Plant Equipment	105,299.47	82,497.03	4,145.00	
	Total Mill Creek Unit 2	66,671,375.40	41,305,842.35	2,445,827.00	38,860,015.35
	Mill Creek Unit 2 Scrubber				
311.00	Structures and Improvements	1,393,403.67	947,198.37	49,891.00	
312.00	Boiler Plant Equipment	34,412,558.24	17,978,498.46	910,681.00	
315.00	Accessory Electric Equipment	4,451,153.72	3,467,639.40	173,336.00	
	Total Mill Creek Unit 2 Scrubber	40,257,115.63	22,393,336.23	1,133,708.00	21,259,628.23
	Mill Creek Unit 3				
311.00	Structures and Improvements	24,487,440.44	15,892,174.24	880,176.00	
312.00	Boiler Plant Equipment	65,259,053.22	41,186,363.84	2,209,150.00	
312.00	Mandated NOX Proj.-2004 Closing	65,597,028.00		0.00	
312.00	Mandated NOX Proj.-2005 Closing	3,198,000.00		0.00	

Louisville Gas and Electric
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Account No. (a)	Description (d)	Cost 12/31/02 (e)	Total Book Depr Reserve 12/31/02 (f)	Cost of Removal Depr Reserve 12/31/02	Adjusted Book Reserve-w/o COR 12/31/2002
314.00	Turbogenerator Units	26,232,206.52	17,259,343.05	899,415.00	
315.00	Accessory Electric Equipment	13,482,711.35	9,003,881.35	478,383.00	
316.00	Misc. Power Plant Equipment	318,625.29	274,298.72	11,945.00	
	Total Mill Creek Unit 3	198,575,064.82	83,616,061.20	4,477,069.00	79,138,992.20
	Mill Creek Unit 3 Scrubber				
311.00	Structures and Improvements	362,866.58	230,008.75	12,763.00	
312.00	Boiler Plant Equipment	52,369,621.74	21,983,261.31	1,180,426.00	
315.00	Accessory Electric Equipment	2,531,772.82	1,845,000.66	95,297.00	
	Total Mill Creek Unit 3 Scrubber	55,264,261.14	24,058,270.72	1,288,486.00	22,769,784.72
	Mill Creek Unit 4				
311.00	Structures and Improvements	58,594,172.78	26,766,630.73	1,650,939.00	
312.00	Boiler Plant Equipment	154,787,100.00	52,421,714.83	3,674,173.00	
312.00	Mandated NOX Proj.-2004 Closing	63,382,718.00		0.00	
312.00	Mandated NOX Proj.-2005 Closing	1,402,000.00		0.00	
312.00	Mandated NOX Proj.-2006 Closing	3,000,000.00		0.00	
314.00	Turbogenerator Units	40,475,497.49	20,964,672.43	1,197,214.00	
315.00	Accessory Electric Equipment	21,428,489.73	11,328,525.97	659,167.00	
316.00	Misc. Power Plant Equipment	3,926,266.27	1,564,750.41	75,580.00	
	Total Mill Creek Unit 4	344,996,244.27	123,046,294.36	7,257,073.00	115,789,221.36
	Mill Creek Unit 4 Scrubber				
311.00	Structures and Improvements	5,079,085.65	2,164,530.50	157,301.00	
312.00	Boiler Plant Equipment	105,450,790.06	31,729,807.81	2,150,481.00	
315.00	Accessory Electric Equipment	5,811,079.36	3,142,825.39	205,013.00	
316.00	Misc. Power Plant Equipment	41,441.04	26,572.02	1,486.00	
	Total Mill Creek Unit 4 Scrubber	116,382,396.11	37,063,735.72	2,514,281.00	34,549,454.72
	Trimble County Unit 1				
311.00	Structures and Improvements	161,248,919.71	47,758,039.32	1,424,072.00	
312.00	Boiler Plant Equipment	235,442,385.84	62,456,671.60	1,737,965.00	
312.00	Mandated NOX Proj.-2004 Closing	2,832,801.00		0.00	
314.00	Turbogenerator Units	66,236,375.14	21,515,114.70	587,435.00	
315.00	Accessory Electric Equipment	56,332,123.79	18,070,820.41	500,288.00	
316.00	Misc. Power Plant Equipment	2,332,701.72	831,971.41	18,544.00	
	Total Trimble County Unit 1	524,425,307.20	150,632,617.44	4,268,304.00	146,364,313.44
	Total Trimble County Unit 1 Scrubber				
311.00	Structures and Improvements	450,053.78	199,877.35	4,369.00	
312.00	Boiler Plant Equipment	54,528,851.05	30,321,313.03	578,706.00	
315.00	Accessory Electric Equipment	2,736,920.21	1,557,453.07	29,683.00	
	Total Trimble County Unit 1 Scrubber	57,715,825.04	32,078,643.45	612,758.00	31,465,885.45
	Total Steam Production Plant	1,805,351,053.32	796,484,692.45	41,078,039.00	755,406,653.45
	HYDRAULIC PLANT Project 289				
	Ohio Falls Plant - Project 289				
331.10	Structures and Improvements	4,995,148.82	4,989,034.51	341,482.00	
332.10	Reservoirs, Dams and Waterways	303,530.35	237,807.60	55,773.00	
333.10	Waterwheel, Turbines and Generators	2,316,031.31	2,528,445.62	214,972.00	
334.10	Accessory Electric Equipment	1,304,908.02	1,052,232.87	129,905.00	
335.10	Miscellaneous Power Plant Equipment	151,460.96	173,144.02	27,979.00	
336.10	Roads, Railroads and Bridges	178,846.99	169,665.39	0.00	
	Total Ohio Falls Plant - Project 289	9,249,926.45	9,150,329.81	770,111.00	8,380,218.81

Other Than Project 289

Ohio Falls Plant - Non Project 289

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Account No. (a)	Description (d)	Cost 12/31/02 (e)	Total Book Depr Reserve 12/31/02 (f)	Cost of Removal Depr Reserve 12/31/02	Adjusted Book Reserve-w/o COR 12/31/2002
331.00	Structures and Improvements	65,796.14	26,465.65	1,596.00	
335.00	Miscellaneous Power Plant Equipment	7,813.67	6,014.78	1,338.00	
336.00	Roads, Railroads and Bridges	1,133.98	592.79	0.00	
	Total Ohio Falls Plant - Non Project 289	74,743.79	33,073.22	2,934.00	30,139.22
	Total Hydraulic Plant	9,324,670.24	9,183,403.03	773,045.00	8,410,358.03
	OTHER PRODUCTION PLANT				
	Cane Run CT's				
341.00	Structures and Improvements	68,931.71	59,101.41	4,340.00	
342.00	Fuel Holders, Producers and Accessory	123,338.90	84,856.13	7,458.00	
344.00	Generators	2,492,496.42	1,590,838.99	120,701.00	
345.00	Accessory Electric Equipment	113,683.82	98,154.10	3,180.00	
	Cane Run CT's	2,798,450.85	1,832,950.64	135,679.00	1,697,271.64
	Zorn CT's				
341.00	Structures and Improvements	8,241.14	8,360.08	552.00	
342.00	Fuel Holders, Producers and Accessory	12,801.77	13,202.27	1,044.00	
344.00	Generators	1,827,580.88	1,688,469.30	115,203.00	
345.00	Accessory Electric Equipment	40,936.08	39,733.30	1,158.00	
	Zorn CT's	1,889,559.87	1,749,764.95	117,957.00	1,631,807.95
	Waterside CT's				
341.00	Structures and Improvements	411,977.94	392,074.27	28,279.00	
342.00	Fuel Holders, Producers and Accessory	124,163.26	115,527.66	9,974.00	
343.00	Prime Movers	2,671,305.84	2,140,319.74	62,459.00	
344.00	Generators	451,117.33	432,486.53	32,232.00	
345.00	Accessory Electric Equipment	342,628.38	167,133.97	5,319.00	
346.00	Misc. Power Plant Equipment	24,766.29	22,894.93	708.00	
	Waterside CT's	4,025,959.04	3,270,437.09	138,971.00	3,131,466.09
	Paddys 11 CT				
342.00	Fuel Holders, Producers and Accessory	9,237.57	9,613.48	753.00	
344.00	Generators	1,523,115.56	1,415,850.36	95,729.00	
345.00	Accessory Electric Equipment	68,109.35	56,264.89	1,625.00	
	Paddys 12 CT	1,600,462.48	1,481,728.73	98,107.00	1,383,621.73
	Paddys 12 CT				
341.00	Structures and Improvements	42,864.53	45,293.55	2,871.00	
342.00	Fuel Holders, Producers and Accessory	12,197.11	12,814.41	972.00	
344.00	Generators	2,991,745.77	2,898,337.55	189,838.00	
345.00	Accessory Electric Equipment	114,337.63	98,654.90	2,759.00	
346.00	Accessory Electric Equipment	1,140.74	1,155.82	31.00	
	Paddys 12 CT	3,162,285.78	3,056,256.24	196,471.00	2,859,785.24
	Paddys 13 CT				
341.00	Structures and Improvements	2,158,898.12	111,888.17	9,087.00	
342.00	Fuel Holders, Producers and Accessory	2,233,773.85	117,701.76	11,443.00	
343.00	Prime Movers	19,627,845.35	969,405.90	31,854.00	
344.00	Generators	5,859,857.93	304,558.38	25,558.00	
345.00	Accessory Electric Equipment	2,778,992.60	141,142.47	5,058.00	
346.00	Misc. Power Plant Equipment	1,260,054.85	66,713.68	2,324.00	
	Paddys 13 CT	33,919,222.70	1,711,408.36	85,324.00	1,626,084.36
	Brown 5 CT				
341.00	Structures and Improvements	858,538.64	44,387.35	3,614.00	
342.00	Fuel Holders, Producers and Accessory	822,580.92	43,235.24	4,214.00	
343.00	Prime Movers	14,126,417.74	695,947.72	22,928.00	
344.00	Generators	3,219,205.40	166,895.19	14,041.00	

Louisville Gas and Electric
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Account No. (a)	Description (d)	Cost 12/31/02 (e)	Total Book Depr Reserve 12/31/02 (f)	Cost of Removal Depr Reserve 12/31/02	Adjusted Book Reserve-w/o COR 12/31/2002
345.00	Accessory Electric Equipment	2,575,301.42	130,470.02	4,688.00	
346.00	Misc. Power Plant Equipment	2,370,656.38	125,200.80	4,374.00	
	Brown 5 CT	23,972,700.50	1,206,136.32	53,857.00	1,152,279.32
	Brown 6 CT				
341.00	Structures and Improvements	69,733.40	5,427.49	522.00	
342.00	Fuel Holders, Producers and Accessory	363,762.04	28,778.79	3,313.00	
343.00	Prime Movers	19,890,998.18	1,475,064.65	57,398.00	
344.00	Generators	2,417,994.54	188,695.05	18,752.00	
345.00	Accessory Electric Equipment	942,589.47	71,661.01	3,041.00	
346.00	Misc. Power Plant Equipment	11,034.25	866.20	36.00	
	Brown 6 CT	23,696,111.88	1,770,494.18	83,062.00	1,687,432.18
	Brown 7 CT				
341.00	Structures and Improvements	105,588.33	18,897.37	764.00	
342.00	Fuel Holders, Producers and Accessory	102,065.03	18,571.39	899.00	
343.00	Prime Movers	20,023,957.45	3,414,831.32	55,870.00	
344.00	Generators	2,421,079.26	434,489.81	18,155.00	
345.00	Accessory Electric Equipment	943,792.03	165,275.71	2,949.00	
346.00	Misc. Power Plant Equipment	11,048.30	2,008.95	35.00	
	Brown 7 CT	23,607,530.40	4,054,074.55	78,672.00	3,975,402.55
	Trimble County CT5				
341.00	Structures and Improvements	1,458,614.33	23,800.78	2,051.00	
342.00	Fuel Holders, Producers and Accessory	97,240.96	1,613.28	166.00	
343.00	Prime Movers	12,205,907.18	189,785.32	6,617.00	
344.00	Generators	1,527,420.57	24,992.49	2,225.00	
345.00	Accessory Electric Equipment	680,686.68	10,867.85	413.00	
	Trimble County CT5	15,969,869.72	251,059.70	11,472.00	239,587.70
	Trimble County CT6				
341.00	Structures and Improvements	1,457,842.69	23,804.36	2,050.00	
342.00	Fuel Holders, Producers and Accessory	97,189.52	1,612.27	166.00	
343.00	Prime Movers	12,199,437.94	189,670.95	6,613.00	
344.00	Generators	1,526,610.88	24,977.32	2,224.00	
345.00	Accessory Electric Equipment	680,326.59	10,861.72	413.00	
	Trimble County CT6	15,961,407.62	250,926.61	11,466.00	239,460.61
	Trimble County Pipeline				
342.00	Fuel Holders, Producers and Accessory	1,835,164.93	39,264.86	2,954.00	
	Trimble County Pipeline	1,835,164.93	39,264.86	2,954.00	36,310.86
	Total Other Production Plant	152,438,725.77	20,674,502.23	1,013,992.00	19,660,510.23
	Total Production Plant	1,967,114,449.33	826,342,597.71	42,865,076.00	783,477,521.71
	TRANSMISSION PLANT				
	Project 289				
353.10	Station Equipment - Non Sys. Control/Com.	0.00	0.00	0.00	
356.10	Overhead Conductors and Devices	0.00	0.00	0.00	
	Total Project 289	0.00			
	Other Than Project 289				
350.10	Land Rights	2,692,773.81	1,862,138.53	0.00	
352.10	Struct. and Improve. - Non Sys. Control/Com.	2,907,082.83	1,319,755.12	101,723.53	
353.10	Station Equipment - Non Sys. Control/Com.	116,591,836.76	58,783,885.97	0.00	
354.00	Towers and Fixtures	23,879,707.58	21,296,311.23	5,507,834.14	
355.00	Poles and Fixtures	26,398,367.92	13,173,697.14	3,046,488.46	
356.00	Overhead Conductors and Devices	33,372,312.49	15,162,638.38	5,302,734.30	
357.00	Underground Conduit	1,868,318.57	273,390.24	0.00	
358.00	Underground Conductors and Devices	5,312,495.53	1,675,296.39	0.00	
	Total Other Than Project 289	212,922,895.49		13,958,780.42	
	Total Transmission Plant	212,922,895.49	113,547,113.00	13,958,780.42	99,588,332.58

Louisville Gas and Electric
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Account No. (a)	Description (d)	Cost 12/31/02 (e)	Total Book Depr Reserve 12/31/02 (f)	Cost of Removal Depr Reserve 12/31/02	Adjusted Book Reserve-w/o COR 12/31/2002
	DISTRIBUTION PLANT				
361.00	Structures and Improvements	5,989,141.37	2,810,349.10	263,384.37	
362.00	Station Equipment	77,088,050.08	25,191,883.20	2,707,221.30	
364.00	Poles, Towers and Fixtures	92,365,173.96	52,705,237.56	51,574,413.02	
365.00	Overhead Conductors and Devices	141,726,406.02	67,131,787.38	33,232,448.85	
366.00	Underground Conduit	52,616,554.86	9,688,016.23	1,442,689.56	
367.00	Underground Conductors and Devices	77,051,441.60	38,273,266.16	8,847,369.95	
	Line Transformers				
368.10	Line Transformers	86,278,030.41	30,721,515.99	2,712,659.47	
368.20	Line Transformers Installations	8,778,300.38	2,574,339.21	227,309.93	
	Total Account 368	95,056,330.79		2,939,969.40	
	Services				
369.10	Underground Services	2,342,286.94	1,563,578.81	112,301.01	
369.20	Overhead Services	20,427,859.34	12,732,459.31	7,605,077.07	
	Total Account 369	22,770,146.28		7,717,378.08	
	Meters & Installations				
370.10	Meters	25,219,577.02	12,282,632.27	925,469.15	
370.20	Meter Installations	8,352,742.98	3,425,757.97	258,237.30	
	Total Account 370	33,572,320.00		1,183,706.45	
	Street Lighting				
373.10	Overhead Street Lighting	22,600,470.37	10,854,699.83	1,858,955.61	
373.20	Underground Street Lighting	32,156,589.32	11,484,555.55	1,545,162.17	
373.40	Street Lighting Trannsformers	87,546.43	63,128.93	0.00	
	Total Account 373	54,844,606.12		3,404,117.78	
	Total Distribution Plant	653,060,171.28	281,503,207.50	113,312,678.76	168,190,528.74
	GENERAL PLANT				
392.20	Transportation Equipment - Trailers	590,217.25	289,107.58	0.00	
394.00	Tools, Shop and Garage Equipment	2,687,990.96	1,172,580.84	0.00	
395.00	Laboratory Equipment	1,548,796.71	914,919.83	0.00	
396.20	Power Operated Equipment - Other	145,466.83	145,466.83	0.00	
	Total General Plant	4,972,471.75	14,464,912.06	0.00	14,464,912.06
	Sub-Total Depreciable Plant	2,838,069,987.85	1,235,857,830.27	170,136,535.18	1,065,721,295.09
	Other Plant (Not Studied)				
392.10	Transportation Equipment - Cars & Trucks	12,069,086.02	9,473,237.14	0.00	
396.10	Power Operated Equipment - Hourly Rated	2,337,037.87	2,469,599.85	0.00	
	Total Other Plant (Not Studied)	14,406,123.89	0.00	0.00	
	Total Depreciable Plant	2,852,476,111.74	1,235,857,830.27	170,136,535.18	1,065,721,295.09
	NON-DEPRECIABLE PLANT				
	INTANGIBLE PLANT				
301.00	Organization	2,240.29	0.00		
302.00	Franchises and Consents	100.00	100.00		
	Total Intangible Plant	2,340.29	100.00	0.00	100.00
	LAND				
310.20	Production Land	5,053,819.49	-30,023.89	0.00	
330.20	Hydraulic Plant	13.00	0.00	0.00	
340.20	Other Production Land	41,125.94	0.00	0.00	
350.20	Transmission Land	888,237.78	0.00	0.00	
360.20	Distribution Land	2,629,414.76	-126,985.13	0.00	
	Total Land	8,612,610.97	-157,009.02	0.00	(157,009.02)
	Total Non-Depreciable Plant	8,614,951.26	-156,909.02	0.00	-156,909.02

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	Total Utility Plant in Service	**2,861,091,063.00**	**1,235,700,921.25**	**170,136,535.18**	**1,065,564,386.07**
	Plant Held for Future Use				
360.20	Substation Land	685,389.54			
362.00	Substation Equipment	11,382.12			
	Total Plant Held for Future Use	696,771.66	0.00		
	Total Electric Plant in Service	**2,861,787,834.66**	**1,235,700,921.25**		

(1) Life Span Method Utilized. Interim Retirement Rate. Service Lives Vary.

Table 1a

Louisville Gas and Electric
Gas Division

Calculation of Cost of Removal in Book Depreciation Reserve as of December 31, 2002 Based Upon Theoretical Depreciation Reserves (By Location and Account) Using Existing Depreciation Parameters

Account No. (a)	Description (d)	Original Cost 12/31/02 (e)	Total Book Depr Reserve 12/31/02 (i)	Adjustment For Omitted Retirements (k)	Plant Depr Reserve 12/31/02 (l)	Cost of Removal Depr Reserve 12/31/02
	DEPRECIABLE PLANT					
	NATURAL GAS STORAGE PLANT					
350.20	Rights of Ways	83,676.14	9,691.16		9,691.16	0.00
	Structures					
351.20	Compressor Station Structures	1,011,754.95	481,954.58		443,937.90	38,016.68
351.30	Measuring and Regulating Station Structures	10,879.81	9,783.40		8,943.57	839.83
351.40	Other Structures	1,148,713.70	627,983.27		579,166.76	48,816.51
	Total Account 351	2,171,348.26		0.00	1,032,048.23	87,673.02
	Wells					
352.20	Reservoirs	400,511.40	420,536.97		420,536.97	0.00
352.30	Nonrecoverable Natural Gas	9,646,655.00	6,989,872.90		6,989,872.90	0.00
352.40	Well Drilling	2,549,654.96	2,360,349.18		2,104,890.64	255,458.54
352.50	Well Equipment	5,037,990.48	2,872,807.26		2,506,210.96	366,596.30
	Total Account 352	17,637,011.84		0.00	12,021,511.47	622,054.84
353.00	Lines	10,349,000.14	6,095,915.63	32,116.18	5,547,182.74	516,616.71
354.00	Compressor Station Equipment	13,404,078.82	6,689,546.37		6,689,546.37	0.00
355.00	Measuring and Regulating Equipment	370,320.90	164,482.43		164,482.43	0.00
356.00	Purification Equipment	9,314,575.58	3,420,245.60		3,000,445.28	419,800.32
357.00	Other Equipment	961,279.76	214,121.80		214,121.80	0.00
	Total Natural Gas Storage Plant	54,271,293.44	30,357,290.55	32,116.18	28,679,029.48	1,646,144.89
	TRANSMISSION PLANT					
365.20	Rights of Way	220,659.05	203,173.96		203,173.96	0.00
367.00	Mains	12,193,974.86	10,763,203.94		8,497,366.02	2,265,837.92
	Total Transmission Plant	12,414,633.91	10,966,377.90	0.00	8,700,539.98	2,265,837.92
	DISTRIBUTION PLANT					
374.22	Other Distribution Land Rights	74,018.23	41,329.75		41,329.75	0.00
	Structures and Improvements					
375.10	City Gate Check Station Struct. and Improve.	133,639.45	68,371.51		56,081.25	12,290.26
375.20	Other Distribution Struct. and Improve.	788,487.48	259,447.97		232,118.15	27,329.82
	Total Account 375	922,126.93		0.00	288,199.40	39,620.08
376.00	Mains	213,002,709.24	60,821,356.04		47,638,638.35	13,182,717.69
378.00	Measuring and Regulating Station Equip. - Gen.	4,590,719.10	1,143,819.63		912,694.45	231,125.18
379.00	Measuring and Reg. Station Eq. - City Gate	2,947,888.13	497,944.10	83,859.07	414,085.03	0.00
380.00	Services	103,680,138.72	42,281,968.92		23,448,692.49	18,833,276.43
381.00	Meters	18,573,635.12	5,672,639.18	1,019,847.12	4,257,616.39	395,175.67
382.00	Meter Installations	7,218,670.36	1,574,182.49	271,757.58	1,128,796.02	173,628.89
383.00	House Regulators	3,106,064.85	1,252,849.08	39,100.59	1,090,958.83	122,789.86
384.00	House Regulator Installations	970,849.46	307,336.05	35,789.97	271,546.08	0.00
385.00	Industrial Measuring and Reg. Station Equip.	142,801.65	61,409.10		61,409.10	0.00
387.00	Other Equipment	65,051.59	12,672.24		12,672.24	0.00
	Total Distribution Plant	355,294,663.38	113,995,326.07	1,450,354.33	79,566,637.94	32,978,333.80
	GENERAL PLANT					
392.20	Transportation Equipment - Trailers	354,281.36	105,520.57		105,520.57	0.00
394.00	Tools, shop and Garage Equipment	2,896,361.96	936,258.93		936,258.93	0.00
395.00	Laboratory Equipment	435,068.27	251,764.70		251,764.70	0.00
	Power Operated Equipment					
396.20	Power Operated Equipment - Other	58,118.72	36,688.40		36,688.40	0.00
	Total Account 396	58,118.72		0.00	36,688.40	
	Total General Plant	3,743,810.31	5,031,606.83	0.00	1,330,232.60	0.00
	Sub-Total Depreciable Plant	425,724,401.04	160,350,603.36	1,482,470.51	118,276,440.00	36,890,316.61

Table 1a

Louisville Gas and Electric
Gas Division

Calculation of Cost of Removal in Book Depreciation Reserve as of December 31, 2002 Based Upon Theoretical Depreciation Reserves (By Location and Account) Using Existing Depreciation Parameters

Account No. (a)	Description (d)	Original Cost 12/31/02 (e)	Total Book Depr Reserve 12/31/02 (f)	Adjustment For Omitted Retirements (k)	Plant Depr Reserve 12/31/02 (l)	Cost of Removal Depr Reserve 12/31/02
	Other Plant (Not Studied)					
392.10	Transportation Equipment - Cars & Trucks	3,209,727.45	2,192,655.87		2,192,655.87	0.00
396.10	Power Operated Equipment - Hourly Rated	2,029,908.51	1,508,720.36		1,508,720.36	0.00
	Total Other Plant (Not Studied)	5,239,635.96	0.00	0.00	3,701,376.23	0.00
	Total Depreciable Plant	430,964,037.00	160,350,603.35	1,482,470.51	121,977,816.23	36,890,316.61
	NON-DEPRECIABLE PLANT					
	INTANGIBLE PLANT					
302.00	Franchises and Consents	1,187.49	800.00		800.00	
352.10	Storage Leaseholds and Rights	552,045.10	573,393.92		573,393.92	
	Total Intangible Plant	553,232.59	574,193.92	0.00	574,193.92	
	LAND					
350.10	Land	32,864.07	3,154.64		3,154.64	
374.11	City Gate Check Station Land	0.00	0.00		0.00	
374.12	Other Distribution Land	62,043.73	-586.44		-586.44	
	Total Land	94,907.80	2,568.20	0.00	2,568.20	
	Total Non-Depreciable Plant	648,140.39	576,762.12	0.00	576,762.12	
	Total Gas Plant in Service	431,612,177.39	160,927,365.47	1,482,470.51	122,554,578.35	

(1) Life Span Method Utilized. Interim Retirement Rate. Service Lives Vary.

Summary		% of Adj'd Resv Depr Reserve
Total Book Depr Reserve 12-31-02	$160,350,603.35	
Adjustment for Omitted Retirements	1,482,470.51	
Adjusted Book Depr Reserve 12-31-02	158,868,132.84	
Plant & Gross Salvage Depr Reserve 12-31-02	121,977,816.23	76.8%
Cost of Removal Depr Reserve 12-31-02	36,890,316.61	23.2%

Table 1a

Louisville Gas and Electric
Common Plant

Calculation of Cost of Removal in Book Depreciation Reserve as of December 31, 2002 Based Upon Theoretical Depreciation Reserves (By Location and Account) Using Existing Depreciation Parameters

Account No. (a)	Description (d)	Cost 12/31/02 (e)	Total Book Depr Reserve 12/31/02 (f)	Adjustment For Omitted Retirements (k)	Plant Depr Reserve 12/31/02 (l)	Cost of Removal Depr Reserve 12/31/02
	DEPRECIABLE PLANT					
	GENERAL PLANT					
389.20	Land Rights	202,094.94	59,152.70		59,152.70	0.00
	Structures and Improvements					
390.10	Structures & Improvements - G.O.	44,852,641.93	12,331,415.90	3,428.37	11,779,055.21	548,932.32
390.20	Structures & Improvements - Trans.	1,803,773.44	429,010.82		405,676.80	23,334.02
390.30	Structures & Improvements - Stores	10,918,534.46	3,921,748.91		3,705,442.11	216,306.80
390.40	Structures & Improvements - Shops	379,370.51	148,753.01		140,073.97	8,679.04
390.60	Structures & Improvements - Micro	694,996.39	91,039.63		87,167.80	3,871.83
	Total Account 390	58,649,316.73	16,921,968.26	3,428.37	16,117,415.88	801,124.01
391.00	Office Furniture & Equipment	16,068,584.97	10,448,071.99		10,448,071.99	0.00
392.20	Transportation Equipment - Trailers	63,404.28	10,771.79	3,112.35	7,659.44	0.00
393.00	Stores Equipment	1,229,701.73	272,869.12		272,869.12	0.00
394.00	Tools, Shop and Garage Equipment	1,928,936.72	558,696.04		558,696.04	0.00
395.00	Laboratory Equipment	22,281.50	11,531.93		11,531.93	0.00
	Power Operated Equipment					
396.20	Power Operated Equipment - Other	14,147.08	6,555.71		6,555.71	0.00
	Total Account 396	14,147.08	6,555.71	0.00	6,555.71	
	Communication Equipment					
397.00	Communication Equipment	29,922,166.57	9,915,062.42		9,915,062.42	0.00
397.10	Communication Equipment - Computer	5,189,546.51	1,514,083.95		1,514,083.95	0.00
	Total Account 397	35,111,713.08	11,429,146.37	0.00	11,429,146.37	0.00
398.00	Miscellaneous Equipment	1,012,231.71	244,741.40		244,741.40	0.00
	TOTAL General Plant	114,302,412.74	55,289,741.92	6,540.72	39,155,840.58	801,124.01
	Sub-Total Depreciable Plant	114,302,412.74	55,289,741.92	6,540.72	39,155,840.58	801,124.01
	Other Plant (Not Studied)					
390.11	Struct & Improv.-G.O. (LG&E Bldg & Actors)	2,409,305.82	1,455,764.48		1,431,945.38	23,819.10
391.30	Computer Equipment	16,385,046.53	8,277,681.43		8,277,681.43	0.00
391.31	Personal Computers	9,794,521.46	5,300,087.10		5,300,087.10	0.00
392.10	Transportation Equipment - Cars & Trucks	223,351.84	121,852.82		121,852.82	0.00
396.10	Power Operated Equipment - Hourly Rated	261,447.33	170,850.79		170,850.79	0.00
	Total Other Plant (Not Studied)	29,073,672.98	0.00		15,302,417.51	23,819.10
	Total Depreciable Plant	143,376,085.72	55,289,741.92	6,540.72	54,458,258.09	824,943.11

Table 1a

Louisville Gas and Electric
Common Plant

Calculation of Cost of Removal in Book Depreciation Reserve as of December 31, 2002 Based Upon Theoretical Depreciation Reserves (By Location and Account) Using Existing Depreciation Parameters

Account No. (a)	Description (d)	Cost 12/31/02 (e)	Total Book Depr Reserve 12/31/02 (j)	Adjustment For Omitted Retirements (k)	Plant Depr Reserve 12/31/02 (l)	Cost of Removal Depr Reserve 12/31/02
	NON-DEPRECIABLE PLANT					
	INTANGIBLE PLANT					
301.00	Organization	83,782.29	0.00	0.00	0.00	
302.00	Franchises and Consents	4,200.00	4,700.00		4,700.00	
303.00	Miscellaneous Intangible Plant - Soft	24,365,948.39	18,018,454.53		18,018,454.53	
303.20	Miscellaneous Intangible Plant - Law	78,799.60	78,799.60		78,799.60	
	TOTAL Intangible Plant	24,532,730.28	18,101,954.13	0.00	18,101,954.13	
	LAND					
389.10	General Land	1,661,503.17	0.00		0.00	
	TOTAL Land	1,661,503.17	0.00	0.00	0.00	
	TOTAL Non-Depreciable Plant	26,194,233.45	18,101,954.13	0.00	18,101,954.13	
	TOTAL Common Utility Plant in Service	169,570,319.17	73,391,698.05	6,540.72	72,560,212.22	

(1) Life Span Method Utilized. Interim Retirement Rate. Service Lives Vary.

Summary		% of Adj'd Resv Depr Reserve
Total Book Depr Reserve 12-31-02	$55,289,741.92	
Adjustment for Omitted Retirements	6,540.72	
Adjusted Book Depr Reserve 12-31-02	55,283,201.20	
Plant & Gross Salvage Depr Reserve 12-31-02	54,458,258.09	98.5%
Cost of Removal Depr Reserve 12-31-02	824,943.11	1.5%

LOUISVILLE GAS AND ELE [illegible] MPANY
DETERMINATION OF NET SALVAGE COMPON[illegible] DEPRECIATION RATES
BASED ON DEPRECIATION STUDY AS OF 12/31/99

Depreciation Rates per Depreciation Study Dated February 2001 — Calculated Net Salvage Rates

ACCOUNT NUMBER	DESCRIPTION	PLANT BALANCE @12/31/99	NET SALVAGE AMOUNT	12/31/99 DEPRECIATION BOOK RESERVE	BALANCE TO BE RECOVERED	EST REM LIFE	ANN DEP AMOUNT	ACCRUAL RATE	Recoverable Balance Excl Net Salvage	ANN DEP AMOUNT Excl. Net Salvage	ACCRUAL RATE Excl Net Salvage	Net salvage Rate	Salv/Depr Ratio
	STEAM PRODUCTION PLANT												
	CANE RUN EXCLUDING S.D.R.S.												
	CANE RUN UNIT #4	42,468,316	-4,246,832	23,256,595	23,458,553	19.0	1,234,661	2.91	19,211,721	1,011,143	2.38	0.53	0.18
	NOx Projects												
	2000	300,000					16,500			16,500			
	2001	200,000					11,579			11,579			
	SUBTOTAL CANE RUN #4	42,968,316					1,262,740	2.94		1,039,222	2.42	0.52	0.18
	CANE RUN UNIT #5	37,061,501	-3,706,150	21,406,211	19,361,440	19.0	1,019,023	2.75	15,655,290	823,963	2.22	0.53	0.19
	NOx Projects												
	2000	200,000					11,000			11,000			
	2001	300,000					17,368			17,368			
	2002	900,000					55,000			55,000			
	SUBTOTAL CANE RUN #5	38,461,501					1,102,391	2.87		907,331	2.36	0.51	0.18
	CANE RUN UNIT #6	70,641,349	-7,064,135	38,244,619	41,460,865	19.3	2,148,231	3.04	34,396,730	1,782,214	2.52	0.52	
	NOx Projects												
	2001	500,000					28,947			28,947			
	SUBTOTAL CANE RUN #6	71,141,349					2,177,178	3.06		1,811,161	2.55	0.51	0.17
	SUBTOTAL CANE RUN EXCL. S.D.R.S.	152,571,166					4,542,310	2.98		3,757,715	2.46	0.51	0.17
	CANE RUN STATION - S.D.R.S.												
	CANE RUN UNIT #4	18,364,208	-1,836,421	20,200,629	FULLY DEPRECIATED								
	CANE RUN UNIT #5	31,250,742	-3,125,074	27,173,390	7,202,426	13.0	554,033	1.77	4,077,352	313,642	1.00	0.77	0.43
	CANE RUN UNIT #6	29,778,214	-2,977,821	24,364,345	8,391,690	12.9	650,519	2.18	5413869	419,660	1.41	0.76	0.35
	SUBTOTAL CANE RUN - S.D.R.S.	79,393,164	-7,939,316	71,738,364	15,594,116		1,204,552	1.52	7,654,800	733,322	0.92	0.59	
	TOTAL CANE RUN	231,964,330					5,746,862	2.48		4,491,037	1.94	0.54	0.22
	MILL CREEK STATION												
	MILL CREEK STATION EXCLUDING S.D.R.S.												
	MILL CREEK UNIT #1	79,004,270	-5,925,320	48,711,263	36,218,327	19.9	1,820,016	2.30	30,293,007	1,522,282	1.93	0.36	0.16
	NOx Projects												
	2000	200,000					10,750			10,750			
	2001	300,000					16,974			16,974			
	2002	1,500,000					89,583			89,563			
	SUBTOTAL MILL CREEK #1	81,004,270					1,937,323	2.39		1,639,569	2.02	0.37	0.15
	MILL CREEK UNIT #2	62,517,114	-4,688,784	38,495,530	28,710,368	21.0	1,367,160	2.19	24,021,584	1,143,885	1.83	0.36	0.16
	NOx Projects												
	2000	200,000					10,750			10,750			
	2001	1,800,000					101,842			101,842			
	SUBTOTAL MILL CREEK #2	64,517,114					1,479,752	2.29		1,256,477	1.95	0.36	0.15

LOUISVILLE GAS AND ELEC ANY
DETERMINATION OF NET SALVAGE COMPONE EPRECIATION RATES
BASED ON DEPRECIATION STUDY AS OF 12/31/99

Depreciation Rates per Depreciation Study Dated February 2001 — Calculated Net Salvage Rates

ACCOUNT NUMBER	DESCRIPTION	PLANT BALANCE @12/31/99	NET SALVAGE AMOUNT	12/31/99 DEPRECIATION BOOK RESERVE	BALANCE TO BE RECOVERED	EST REM LIFE	ANN DEP AMOUNT	ACCRUAL RATE	Recoverable Balance Excl Net Salvage	ANN DEP AMOUNT Excl. Net Salvage	ACCRUAL RATE Excl Net Salvage	Net salvage Rate	Salv/Depr Ratio
	MILL CREEK UNIT #3	129,452,951	-9,708,971	72,394,082	66,767,860	25.3	2,639,046	2.04	57,058,889	2,255,292	1.74	0.30	0.15
	NOx Projects												
	2000	2,000,000					107,500			107,500			
	2001	21,000,000					1,188,158			1,188,158			
	2002	23,000,000					1,373,611			1,373,611			
	SUBTOTAL MILL CREEK #3	175,452,951					5,308,315	3.03		4,924,561	2.81	0.22	0.07
	MILL CREEK UNIT #4	249,236,600	-18,692,745	101,613,573	166,315,772	29.7	5,599,858	2.25	147,623,027	4,970,472	1.99	0.25	0.11
	NOx Projects												
	2000	3,500,000					188,125			188,125			
	2001	43,000,000					2,432,895			2,432,895			
	2002	4,000,000					238,889			238,889			
	SUBTOTAL MILL CREEK #4	299,736,600					8,459,787	2.82		7,830,381	2.61	0.21	0.07
	SUBTOTAL MILL CREEK EXCL. S.D.R.S.	620,710,935					17,185,157	2.77		15,650,988	2.52	0.25	0.09
	MILL CREEK STATION - S.D.R.S.												
	MILL CREEK STATION UNIT #1	40,265,952	-3,019,946	22,251,408	21,034,490	13.4	1,569,736	3.90	18,014,544	1,344,369	3.34	0.56	0.14
	MILL CREEK STATION UNIT #2	35,126,006	-2,634,450	18,852,860	18,907,596	13.5	1,400,563	3.99	16,273,146	1,205,418	3.43	0.56	0.14
	MILL CREEK STATION UNIT #3	43,847,083	-3,288,531	20,250,795	26,884,819	13.5	1,991,466	4.54	23,596,288	1,747,873	3.99	0.56	0.12
	MILL CREEK STATION UNIT #4	113,601,807	-8,520,136	25,550,492	96,571,451	15.8	6,112,117	5.38	88051315	5,572,868	4.91	0.47	0.09
	SUBTOTAL MILL CREEK STATION - S.D.R.S.	232,840,848	-17,463,063	86,905,555	163,398,356		11,073,886	4.76	145,935,293	9,870,528	4.24	0.52	0.11
	TOTAL MILL CREEK STATION	853,551,783					28,259,043	3.31	145,935,293	25,521,516	2.99	0.32	0.10
	TRIMBLE COUNTY												
	TRIMBLE COUNTY - UNIT #1	485,195,999	-14,556,880	115,753,922	383,997,957	34.3	11,195,276	2.31	369,442,077	10,770,906	2.22	0.09	0.04
	NOx Projects												
	2000	4,200,000					144,200			144,200			
	2001	30,000,000					1,065,517			1,065,517			
	2002	2,800,000					103,000			103,000			
	SUBTOTAL TRIMBLE COUNTY UNIT #1	522,195,999					12,507,993	2.40	522,195,999	12,083,623	2.31	0.08	0.03
	TRIMBLE COUNTY - S.D.R.S	57,722,892	-1,731,687	25,217,887	34,236,692	17.1	2,002,146	3.47	32505005	1,900,877	3.29	0.18	0.05
	TOTAL TRIMBLE COUNTY	579,918,891					14,510,139	2.50	554,701,004	13,984,501	2.41	0.09	0.04
	TOTAL DEPREC. STEAM PROD. PLANT	1,665,435,004					48,516,044	2.91	700,636,297	43,997,054	2.64	0.27	0.09
	OTHER PRODUCTION PLANT												
	WATERSIDE	3,559,629	0	3,074,962	484,667	10.5	46,159	1.30	484,667	46,159	1.30	0.00	0.00
	ZORN AND RIVER ROAD	1,889,560	0	1,644,039	245,521	10.5	23,383	1.24	245,521	23,383	1.24	0.00	0.00
	PADDY'S RUN UNIT 11	1,592,575	0	1,382,409	210,166	10.5	20,016	1.26	210,166	20,016	1.26	0.00	0.00
	PADDY'S RUNT UNIT 12	3,161,146	0	2,714,827	446,319	10.5	42,507	1.34	446,319	42,507	1.34	0.00	0.00
	CANE RUN	2,061,814	0	1,955,790	106,024	10.5	10,098	0.49	106,024	10,098	0.49	0.00	0.00
	E.W. BROWN UNIT 6	22,207,671	0	388,507	21,819,164	28.5	765,585	3.45	21,819,164	765,585	3.45	0.00	0.00
	E.W. BROWN UNIT 7	22,371,850	0	378,333	21,993,517	29.5	745,543	3.33	21,993,517	745,543	3.33	0.00	0.00
	E.W. BROWN UNIT PIPELINE UNIT 11	248,122	0	4,196	243,926	29.5	8,269	3.33	243926	8,269	3.33	0.00	0.00
	TOTAL OTHER PRODUCTION PLANT	57,092,387	0	11,543,083	45,549,304		1,661,560	2.91	45,549,304	1,661,558	2.91	0.00	0.00

LOUISVILLE GAS AND ELE[illegible]ANY
DETERMINATION OF NET SALVAGE COMPON[illegible] DEPRECIATION RATES
BASED ON DEPRECIATION STUDY AS OF 12/31/99

Depreciation Rates per Depreciation Study Dated February 2001 | **Calculated Net Salvage Rates**

ACCOUNT NUMBER	DESCRIPTION	PLANT BALANCE @12/31/99	NET SALVAGE AMOUNT	12/31/99 DEPRECIATION BOOK RESERVE	BALANCE TO BE RECOVERED	EST REM LIFE	ANN DEP AMOUNT	ACCRUAL RATE	Recoverable Balance Excl Net Salvage	ANN DEP AMOUNT Excl. Net Salvage	ACCRUAL RATE Excl Net Salvage	Net salvage Rate	Salv/Depr Ratio
	TRANSMISSION PLANT												
350.40	LINES LAND RIGHTS	2,127,674	0	1,081,238	1,046,436	37.5	27,905	1.31	1,046,436	27,905	1.31	0.00	0.00
352.10	SUBSTATION STRUCTURES	1,956,161	-195,616	1,082,608	1,069,169	27.0	39,599	2.02	873,553	32,354	1.65	0.37	0.18
353.20	SUBSTATION EQUIPMENT	94,874,337	0	47,351,479	47,522,858	23.9	1,988,404	2.10	47,522,858	1,988,404	2.10	0.00	0.00
354.20	TOWERS & FIXTURES	17,608,805	-4,402,201	14,137,690	7,873,316	18.6	423,297	2.40	3,471,115	186,619	1.06	1.34	0.56
355.20	POLES & FIXTURES	21,962,776	-4,392,555	9,199,615	17,155,716	26.5	647,386	2.95	12,763,161	481,629	2.19	0.75	0.26
356.20	OH CONDUCTORS & DEVICES	23,136,372	-5,784,093	15,738,240	13,182,225	19.6	672,563	2.91	7,398,132	377,456	1.63	1.28	0.44
357.00	UNDERGROUND CONDUIT	1,351,011	0	143,260	1,207,751	45.2	26,720	1.98	1,207,751	26,720	1.98	0.00	0.00
358	UG CONDUCTORS & DEVICES	4,874,292	0	569,907	4,304,385	35.7	120,571	2.47	4304385	120,571	2.47	0.00	0.00
	TOTAL DEPREC. TRANSMISSION PLANT	167,891,428	-14,774,465	89,304,037	93,361,856		3,946,445	2.35	78,587,391	3,241,658	1.93	0.42	0.18
	DISTRIBUTION PLANT												
361.10	SUBSTATION STRUCTURES - A	5,303,823	-530,382	2,874,073	2,960,132	25.3	117,001	2.21	2,429,750	96,038	1.81	0.40	0.18
361.30	OTHER STRUCTURES	349,798	-34,980	173,397	211,381	27.2	7,771	2.22	176,401	6,485	1.85	0.37	0.17
362.10	SUBSTATION EQUIPMENT - A	71,298,623	-3,564,931	26,525,718	48,337,836	26.4	1,830,979	2.57	44,772,905	1,695,943	2.38	0.19	0.07
362.20	SUBSTATION EQUIPMENT - B	2,562,044	-128,102	1,863,297	826,849	10.0	82,685	3.23	698,747	69,875	2.73	0.50	0.16
364.00	POLES, TOWERS, & FIXTURES	82,950,558	-37,327,751	42,633,320	77,644,989	26.4	2,941,098	3.55	40,317,238	1,527,168	1.84	1.70	0.48
365.00	OH CONDUCTORS	108,597,726	-27,149,432	49,766,083	85,981,075	20.7	4,153,675	3.82	58,831,643	2,842,108	2.82	1.21	0.32
366.00	UNDERGROUND CONDUIT	45,391,860	-2,269,594	7,648,812	40,012,662	59.2	675,890	1.49	37,743,068	637,552	1.40	0.08	0.05
367.00	UG CONDUCTORS & DEVICES	60,520,829	-6,052,083	22,586,092	43,986,820	23.6	1,863,848	3.08	37,934,737	1,607,404	2.66	0.42	0.14
368.00	LINE TRANSFORMERS	85,618,247	-8,561,825	29,828,097	64,351,975	27.8	2,314,819	2.70	55,790,150	2,006,840	2.34	0.36	0.13
369.10	UNDERGROUND SERVICES	2,340,944	-117,047	900,630	1,557,361	20.7	75,235	3.21	1,440,314	69,580	2.97	0.24	0.08
369.20	OVERHEAD SERVICES	20,165,987	-12,099,592	12,662,690	19,602,889	21.8	899,215	4.46	7,503,297	344,188	1.71	2.75	0.62
370.00	METERS	30,301,866	-3,030,187	11,654,478	21,677,575	21.2	1,022,527	3.37	18,647,388	879,594	2.90	0.47	0.14
373.10	OVERHEAD STREET LIGHTING	20,936,271	-2,093,627	9,623,080	13,406,818	10.8	1,241,372	5.93	11,313,191	1,047,518	5.00	0.93	0.16
373.20	UNDERGROUND STREET LIGHTING	24,234,877	-2,423,488	7,945,534	18,712,831	17.8	1,051,283	4.34	16,289,343	915,132	3.78	0.56	0.13
373.40	STREET LIGHTING TRANSFORMERS	84,847	0	84,847	0			0.00	0	0	0.00	0.00	0.00
373.5	STREET LIGHTING TRANS. INSTL.	2,699	0	2,699	0			0.00	0	0	0.00	0.00	0.00
	TOTAL DEPREC. DISTR. PLANT	560,661,019	-105,383,021	226,772,847	439,271,193		18,277,398	3.26	333,886,172	13,745,425	2.45	0.81	0.25
	GENERAL PLANT												
392.20	TRANSPORTATION EQUIP-TRAILERS	509,511	50,951	151,447	307,113	23.2	13,238	2.60	358,064	15,434	3.03	-0.43	-0.17
394.10	SHOP EQUIPMENT	63,952	0	30,119	33,833	19.0	1,781	2.78	33,833	1,781	2.78	0.00	0.00
394.30	OTHER EQUIPMENT	1,778,454	177,845	394,407	1,206,202	19.4	62,175	3.50	1,384,047	71,343	4.01	-0.52	-0.15
395.00	LABORATORY EQUIPMENT	1,552,488	77,624	580,979	893,885	21.3	41,966	2.70	971,509	45,611	2.94	-0.23	-0.08
396.2	POWER OPERATED EQUIPMENT-TRAILERS	145,467	14,547	78,627	52,293	17.0	3,076	2.11	66840	3,932	2.70	-0.59	-0.28
	TOTAL DEPREC. GENERAL PLANT	4,049,872	320,967	1,235,579	2,493,326		122,236	3.02	2,814,293	138,100	3.41	-0.39	-0.13
	TOTAL DEPREC. ELECTRIC PLANT	2,455,129,690					72,523,683	2.95	1,161,476,467	82,783,793	2.56	0.40	0.13

THIS SCHEDU... CREATED FOR KENTUCKY UTILITIES
CREATED ON 10/05/00 BY MARCY STEFAN
REV. 1/23/01 CHANGED GHENT SALV% TO -9%

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KENTUCKY UTILITIES COMPANY
DEPRECIATION STUDY AS OF 12/31/99
SCHEDULE OF INDICATED REMAINING LIFE ACCRUAL RATES

Calculated Net Salvage Rates

ACCOUNT NUMBER	DESCRIPTION	PLANT BALANCE @12/31/99	NET SALVAGE AMOUNT	12/31/99 DEPRECIATION BOOK RESERVE	BALANCE TO BE RECOVERED	EST REM LIFE	ANN DEP AMOUNT	ACCRUAL RATE	Recoverable Balance Excl Net Salvage	ANN DEP AMOUNT Excl. Net Salvage	ACCRUAL RATE Excl Net Salvage	Net salvage Rate	Salv/Depr Ratio
	STEAM PRODUCTION PLANT												
	E. W. BROWN PLANT												
	E. W. BROWN UNIT #1	50,695,819	-7,097,415	28,402,110	29,391,124	19.5	1,507,237	2.97	22,293,709	1,143,267			
	NOx Projects												
	2001	1,200,000					0						
	SUBTOTAL E.W. BROWN UNIT #1	51,895,819					1,507,237	2.90		1,143,267	2.26	0.65	0.22
	E. W. BROWN UNIT #2	35,834,794	-5,016,871	20,270,986	20,580,679	19.4	1,060,880	2.96	15,563,808	802,258			
	NOx Projects												
	2002	1,300,000					82,333			82,333			
	Other Mandatory Projects												
	2002	2,500,000					0						
	SUBTOTAL E.W. BROWN UNIT #2	39,634,794					1,143,193	2.88		884,591	2.38	0.50	0.17
	E. W. BROWN UNIT #3	114,565,653	-16,039,191	66,052,199	64,552,645	19.6	3,293,502	2.87	48,513,454	2,475,176			
	NOx Projects												
	2002	2,000,000					126,667			126,667			
	2003	17,200,000					1,153,412			1,153,412			
	2004	23,000,000					1,638,750			1,638,750			
	Other Mandatory Projects									0			
	2002	600,000					0			0			
	2003	900,000					0			0			
	2004	700,000					0			0			
	SUBTOTAL E.W. BROWN UNIT #3	158,865,653					8,212,330	3.91		5,394,005	3.40	0.52	0.13
	TOTAL E. W. BROWN PLANT	250,395,266					6,862,761	3.54					
	GHENT PLANT												
	GHENT PLANT EXCL. S.D.R.S.												
	GHENT UNIT #1	129,982,729	-11,698,446	86,817,929	54,863,246	21.4	2,563,703	1.97	43,164,800	2,017,047			
	NOx Projects												
	2001	2,000,000					114,737			114,737			
	2002	7,000,000					423,889			423,889			
	2003	40,000,000					2,564,706			2,564,706			
	Other Mandatory Projects												
	2004	1,800,000					0						
	2005	700,000					0						
	SUBTOTAL GHENT UNIT #1	181,482,729					5,667,035	3.12	43,164,800	5,120,378	2.82	0.30	0.10
	GHENT UNIT #2	138,193,639	-12,437,478	91,681,162	58,949,905	24.5	2,406,119	1.74	46,512,477	1,898,488			
	NOx Projects												
	2003	4,000,000					256,471			256,471			
	Other Mandatory Projects												
	2001	120,000					0						

KENTUCKY UTILITIES COMPANY
DEPRECIATION STUDY AS OF 12/31/99
SCHEDULE OF INDICATED REMAINING LIFE ACCRUAL RATES

Calculated Net Salvage Rates

ACCOUNT NUMBER	DESCRIPTION	PLANT BALANCE @12/31/99	NET SALVAGE AMOUNT	12/31/99 DEPRECIATION BOOK RESERVE	BALANCE TO BE RECOVERED	EST REM LIFE	ANN DEP AMOUNT	ACCRUAL RATE	Recoverable Balance Excl Net Salvage	ANN DEP AMOUNT Excl. Net Salvage	ACCRUAL RATE Excl Net Salvage	Net salvage Rate	Salv/Depr Ratio
	2002	730,000					0						
	2003	910,000					0						
	2004	750,000					0						
	SUBTOTAL GHENT UNIT #2	144,703,639					2,662,590	1.84	46,612,477	2,154,939	1.49	0.35	0.19
	GHENT UNIT #3	279,724,512	-25,175,206	170,190,684	134,709,034	28.7	4,693,695	1.68	109,533,828	3,816,510			
	NOx Projects												
	2000	120,000					6,640			6,640			
	2001	4,000,000					229,474			229,474			
	2002	32,000,000					1,937,778			1,937,778			
	2003	5,000,000					320,588			320,588			
	Other Mandatory Projects												
	2001	990,000					0						
	2002	240,000					0						
	2003	960,000					0						
	2004	280,000					0						
	SUBTOTAL GHENT UNIT #3	323,314,512					7,188,075	2.22	109,533,828	6,310,889	1.95	0.27	0.12
	GHENT UNIT #4	259,939,578	-23,394,562	142,439,606	140,894,534	31.9	4,418,757	1.70	117,499,972	3,683,365			
	NOx Projects												
	2001	2,000,000					114,737			114,737			
	2002	12,500,000					756,944			756,944			
	2003	26,500,000					1,699,118			1,699,118			
	Other Mandatory Projects									0			
	2001	2,960,000					0						
	2002	6,560,000					0						
	2003	10,680,000					0						
	2004	880,000					0						
	2005	960,000					0						
	SUBTOTAL GHENT UNIT #4	322,959,578					6,987,656	2.16		6,254,184	1.94	0.23	0.10
	TOTAL GHENT PLANT EXCL. S.D.R.S.	972,460,458					22,505,255	2.31					
	GHENT PLANT- S.D.R.S.												
	GHENT UNIT #1	114,258,493	-10,283,264	20,805,355	103,736,402	16.0	6,483,526	5.67	93,453,138	5,840,821	5.11	0.56	0.10
	GHENT UNIT #2												
	2001	3,200,000					183,679	5.74					
	2002	12,800,000					775,111	6.06					
	2003	14,400,000					923,294	6.41					
	2004	1,600,000					109,000	6.81					
	SUBTOTAL GHENT#2	32,000,000					1,990,984	6.22					
	TOTAL GHENT PLANT-S.D.R.S.	146,258,493					8,474,509	5.79					
	TOTAL GHENT PLANT	1,118,716,951					30,979,764	2.77					
	GREEN RIVER PLANT												
	GREEN RIVER UNITS #1 & #2	17,856,942	-2,678,541	14,962,034	5,573,449	18.2	306,233	1.71	2,894,908	159,061	0.89	0.82	0.48
	GREEN RIVER UNIT #3	14,643,567	-2,196,535	12,503,983	4,336,119	18.4	235,659	1.61	2,139,584	116,282			

KENTUCKY UTILITIES COMPANY
DEPRECIATION STUDY AS OF 12/31/99
SCHEDULE OF INDICATED REMAINING LIFE ACCRUAL RATES

Calculated Net Salvage Rates

ACCOUNT NUMBER	DESCRIPTION	PLANT BALANCE @12/31/99	NET SALVAGE AMOUNT	12/31/99 DEPRECIATION BOOK RESERVE	BALANCE TO BE RECOVERED	EST REM LIFE	ANN DEP AMOUNT	ACCRUAL RATE	Recoverable Balance Excl Net Salvage	ANN DEP AMOUNT Excl. Net Salvage	ACCRUAL RATE Excl Net Salvage	Net salvage Rate	Salv/Depr Ratio
	NOx Projects												
	2000	10,000					575			575			
	2002	1,090,000					69,639			69,639			
	SUBTOTAL GREEN RIVER UNIT #3	15,743,567					305,873	1.94	2,139,584	186,498	1.18	0.76	0.39
	GREEN RIVER UNIT #4	32,916,992	-4,937,849	18,166,744	19,690,097	19.3	1,020,212	3.10	14,752,248	764,365	2.32	0.78	0.25
	TOTAL GREEN RIVER PLANT	66,519,501					1,632,318	2.45					
	PINEVILLE UNIT #3	8,131,876	-1,138,463	6,516,894	2,753,445	17.6	156,446	1.92	1,614,982	91,760			
	NOx Projects												
	2000	10,000					570			570			
	2002	700,000					44,333			44,333			
	SUBTOTAL PINEVILLE UNIT #3	8,841,876					201,349	2.28		136,664	1.56	0.73	0.32
	SYSTEM LAB	1,695,312	0	615,007	1,080,305	15.1	71,543	4.22					
	TYRONE UNIT #3	17,321,891	-3,810,772	15,038,059	6,094,404	18.2	334,857	1.93	2,283,832	126,474			
	NOx Projects												
	2000	30,000					1,830			1,830			
	2001	1,070,000					68,705			68,705			
	Other Mandatory Projects												
	2001	600,000					0						
	SUBTOTAL TYRONE UNIT #3	19,021,891					405,392	2.13		196,010	1.03	1.10	0.52
	TOTAL DEPREC. STEAM PRODUCTION PLANT	1,465,193,597					42,153,127	2.88					
	HYDRAULIC PRODUCTION PLANT												
	DIX DAM	9,774,892	-889,558	7,168,550	3,495,900	22.5	155,373	1.59					
	LOCK 7	837,792	-251,338	626,233	462,897	22.5	20,573	2.46					
	TOTAL DEPREC.HYDRAULIC PRODUCTION PLANT	10,612,684	-1,140,896	7,794,783	3,958,797		175,946	1.66					
	OTHER PRODUCTION PLANT												
	E. W. BROWN PLANT												
	E. W. BROWN #6	36,250,643	0	1,230,724	35,019,919	28.5	1,228,769	3.39					
	E. W. BROWN #7	37,455,942	0	1,229,257	36,226,685	29.5	1,228,023	3.28					
	E. W. BROWN #8	27,610,211	0	3,897,919	23,712,292	24.5	967,849	3.51					
	E. W. BROWN #9	36,721,763	0	6,242,262	30,479,501	24.5	1,244,081	3.39					
	E. W. BROWN #10	27,659,729	0	4,105,124	23,554,605	24.5	961,412	3.48					
	E. W. BROWN #11	34,693,336	0	3,312,496	31,380,840	25.5	1,230,621	3.55					
	TOTAL E. W. BROWN PLANT	200,391,624	0	20,017,782	180,373,842		6,860,735	3.42					
	TRANSMISSION PLANT												
350.10	LAND RIGHTS	22,921,429	0	7,918,958	15,002,471	48.8	307,428	1.34	15,002,471	307,428	1.34	0.00	0.00
352.00	STRUCTURES & IMPROVEMENTS	7,376,773	-3,319,548	3,377,416	7,318,905	37.4	195,693	2.65	3,998,357	106,935	1.45	1.20	0.45

KENTUCKY UTILITIES COMPANY
DEPRECIATION STUDY AS OF 12/31/99
SCHEDULE OF INDICATED REMAINING LIFE ACCRUAL RATES

of 4

ACCOUNT NUMBER	DESCRIPTION	PLANT BALANCE @12/31/99	NET SALVAGE AMOUNT	12/31/99 DEPRECIATION BOOK RESERVE	BALANCE TO BE RECOVERED	EST REM LIFE	ANN DEP AMOUNT	ACCRUAL RATE
353.10	SUBSTATION EQUIPMENT	134,161,967	-13,418,197	53,200,640	94,399,524	31.6	2,988,538	2.21
353.20	MICROWAVE EQUIPMENT	11,419,299	-1,141,930	6,567,090	5,994,139	8.5	705,193	6.18
354.00	TOWERS & FIXTURES	60,000,913	-33,000,502	33,399,995	59,601,420	35.0	1,702,898	2.84
355.00	POLES & FIXTURES	68,210,779	-40,926,467	39,376,846	69,760,400	25.4	2,746,472	4.03
356.00	OH CONDUCTORS & DEVICES	115,897,447	-52,153,651	69,126,108	98,925,190	26.3	3,761,414	3.25
357.00	UNDERGROUND CONDUIT	432,475	-43,248	69,719	406,004	46.8	8,675	2.01
358.00	UG CONDUCTORS & DEVICES	1,114,762	-55,738	449,037	721,463	18.4	39,210	3.52
	TOTAL DEPREC. TRANSMISSION PLANT	421,555,844	-144,059,481	213,485,809	352,129,518		12,435,521	2.95
	DISTRIBUTION PLANT							
360.10	LAND RIGHTS	1,418,333	0	653,369	762,964	47.1	16,199	1.14
361.00	STRUCTURES & IMPROVEMENTS	3,122,843	-312,264	1,179,098	2,255,809	38.3	58,898	1.89
362.00	STATION EQUIPMENT	81,088,044	-8,108,804	28,317,713	60,879,135	33.5	1,817,288	2.24
364.00	POLES, TOWERS, & FIXTURES	148,606,983	-56,874,047	65,143,879	150,339,161	28.7	5,238,298	3.52
365.00	OH CONDUCTORS & DEVICES	140,791,529	-63,356,188	65,641,365	138,506,352	32.6	4,248,661	3.02
366.00	UNDERGROUND CONDUIT	1,545,108	-154,511	723,065	976,554	36.1	27,051	1.75
367.00	UG CONDUCTORS & DEVICES	31,999,710	-3,199,971	8,323,554	28,876,127	27.4	1,053,873	3.29
368.00	LINE TRANSFORMERS	185,510,765	-18,551,079	63,859,811	140,202,253	31.4	4,465,040	2.41
369.00	SERVICES	72,773,393	-32,748,027	28,827,439	76,893,981	28.1	2,729,323	3.75
370.00	METERS	56,069,039	-5,806,904	24,100,086	37,575,857	24.0	1,565,661	2.79
371.00	INSTALL. ON CUSTOMERS' PREM.	17,944,246	0	4,673,887	13,270,358	11.8	1,124,607	8.27
373.00	STREET LIGHTING & SIG. SYSTEM	35,688,092	-3,888,809	13,435,454	27,141,447	19.1	1,421,918	3.85
	TOTAL DEPREC. DISTR. PLANT	777,767,914	-202,600,604	302,878,520	677,479,998		23,765,917	3.06
	GENERAL PLANT							
390.10	IMPROVEMENTS TO OWNED PROPERTY	31,138,794	0	10,069,805	21,068,989	38.4	548,672	1.76
391.10	OFFICE EQUIPMENT	2,811,209	0	977,765	1,833,444	11.2	163,700	5.82
393.00	STORES EQUIPMENT	831,744	31,587	346,442	253,715	14.0	18,123	2.87
394.00	TOOLS, SHOP, & GARAGE EQUIPMENT	2,835,759	141,788	971,102	1,722,869	22.2	77,807	2.74
395.00	LABORATORY EQUIPMENT	3,150,709	84,521	997,880	2,056,308	20.7	99,435	3.16
396.00	POWER OPERATED EQUIPMENT	203,917	40,763	96,429	66,705	9.2	7,251	3.56
397.00	COMMUNICATION EQUIPMENT	3,998,830	0	2,677,579	1,321,051	8.3	142,048	3.55
398.00	MISC. EQUIPMENT	542,572	0	272,191	270,381	9.6	28,165	5.19
	TOTAL DEPREC. GENERAL PLANT	45,313,334	308,679	16,409,193	28,595,462		1,085,001	2.39
	TOTAL DEPREC. ELECTRIC PLANT	2,920,824,997					86,476,247	2.96
	INTANGIBLE PLANT	11,958,316		19,717				
310.00	LAND & LAND RIGHTS	10,198,525						
	PINEVILLE UNITS #1 & #2	1,673,670		1,907,984				
	TYRONE #1 & #2	6,482,245		7,908,339				
	HAFLING #1, #2, & #3	4,683,527		4,883,527				
330.00	LAND	13,480						
340.00	LAND	98,603						
350.00	LAND	1,163,116						
360.00	LAND	1,426,948						
389.00	LAND & LAND RIGHTS	3,456,077						
390.00	STRUCTURES	583,404		432,406				
391.00	COMPUTER EQUIPMENT	7,487,189		194,197				
392.00	TRANSPORTATION EQUIPMENT	23,762,286		17,966,454				
	TOTAL ELECTRIC PLANT	2,993,810,379						

Calculated Net Salvage Rates

ACCOUNT NUMBER	Recoverable Balance Excl Net Salvage	ANN DEP AMOUNT Excl. Net Salvage	ACCRUAL RATE Excl Net Salvage	Net salvage Rate	Salv/Depr Ratio
353.10	60,981,327	2,546,583	1.90	0.31	0.14
353.20	4,852,209	570,848	5.00	1.16	0.19
354.00	28,600,918	780,026	1.27	1.57	0.55
355.00	28,833,933	1,135,194	1.66	2.36	0.59
356.00	46,771,339	1,778,378	1.53	1.71	0.53
357.00	362,756	7,751	1.79	0.21	0.11
358.00	665,725	36,181	3.25	0.27	0.08
360.10	762,964	16,199	1.14	0.00	0.00
361.00	1,943,545	50,745	1.63	0.26	0.14
362.00	52,770,331	1,575,234	1.94	0.30	0.13
364.00	83,465,114	2,908,192	1.96	1.57	0.44
365.00	75,150,164	2,305,220	1.64	1.38	0.45
366.00	822,043	22,771	1.47	0.28	0.16
367.00	25,676,156	937,086	2.93	0.36	0.11
368.00	121,851,174	3,874,241	2.09	0.32	0.13
369.00	43,945,954	1,563,913	2.15	1.60	0.43
370.00	31,968,953	1,332,040	2.38	0.42	0.15
371.00	13,270,358	1,124,607	8.27	0.00	0.00
373.00	23,452,638	1,227,887	3.33	0.52	0.14
390.10	21,068,989	548,672	1.76	0.00	0.00
391.10	1,833,444	163,700	5.82	0.00	0.00
393.00	285,302	20,379	3.23	-0.36	-0.12
394.00	1,864,657	83,994	2.96	-0.23	-0.08
395.00	2,152,829	104,001	3.30	-0.14	-0.05
396.00	107,468	11,663	5.73	-2.17	-0.61
397.00	1,321,051	142,048	3.56	0.00	0.00
398.00	270,381	28,165	5.19	0.00	0.00

Louisville Gas and Electric Company
Estimated Removal Cost in Reserve
at December 2002

Property Group		Reserve Balance 12-31-02	Salv/Dep Ratio	Estimated Net Salvage	% of Reserve
LG&E					
	Total Steam Production Plant	796,484,692.45	-	81,279,833.36	10%
	Ohio Falls Hydraulic Production Plant	9,183,403.03	-	-	0%
	Total Other Production Plant	20,674,502.23	-	-	0%
	Total Transmission Plant	113,547,113.18	-	20,025,125.45	18%
	Total Distribution Plant	281,376,222.37	-	66,721,682.50	24%
	Total General Plant	14,464,912.06	-	(2,532,915.75)	-18%
	TOTAL ELECTRIC	1,235,730,845.32		165,493,725.56	13%
	TOTAL GAS *	158,773,492.53	-	41,317,003.31	26%
	TOTAL COMMON	73,242,363.78	-	1,963,218.31	3%
TOTAL LG&E		1,467,746,701.63		208,773,947.17	14%
KU					
	Total Steam Production Plant	794,854,592.78	-	81,279,833.36	10%
	Ohio Falls Hydraulic Production Plant	8,323,904.23	-	-	0%
	Total Other Production Plant	50,312,904.75	-	-	0%
	Total Transmission Plant	249,396,208.57	-	20,025,125.45	8%
	Total Distribution Plant	371,679,811.83	-	66,721,682.50	18%
	Total General Plant	49,485,369.49	-	(2,532,915.75)	-5%
TOTAL KU		1,235,730,845.32		165,493,725.56	13%
TOTAL UTILITY		2,703,477,546.95		374,267,672.73	14%

Louisville Gas and Electric Company
Estimated Removal Cost in Reserve
at December 2002

Property Group	Reserve Balance 12-31-02	Salv/Dep Ratio	Estimated Removal Cost
Intangible Plant			
302 Franchises and Consents	100	0%	-
303 Misc Intangible Plant	-		
Total Intangible Plant	100		-
Steam Production Plant			
Cane Run 1	9,717,921	0%	-
Cane Run 2	3,599,596	0%	-
Cane Run 3	9,360,592	0%	-
Cane Run 4	27,104,122	18%	4,878,741.94
Cane Run 5	24,639,026	18%	4,435,024.74
Cane Run 6	42,775,260	17%	7,271,794.17
Cane Run 4 FGD	22,203,603	0%	-
Cane Run 5 FGD	29,596,490	43%	12,726,490.51
Cane Run 6 FGD	26,114,613	35%	9,140,114.44
Mill Creek 1	60,261,697	15%	9,039,254.60
Mill Creek 2	41,305,842	15%	6,195,876.35
Mill Creek 3	83,616,061	7%	5,853,124.28
Mill Creek 4	123,046,294	7%	8,613,240.61
Mill Creek 1 FGD	26,916,971	14%	3,768,375.95
Mill Creek 2 FGD	22,393,336	14%	3,135,067.07
Mill Creek 3 FGD	24,058,271	12%	2,886,992.49
Mill Creek 4 FGD	37,063,736	9%	3,335,736.21
Trimble County 1	150,632,617	3%	4,518,978.52
Trimble County 1 FGD	32,078,643	5%	1,603,932.17
Total Steam Production Plant	796,484,692		81,279,833
Ohio Falls Hydraulic Production Plant	9,183,403	0%	-
Other Production Plant			
Cane Run 11	1,832,951	0%	-
Zorn	1,749,765	0%	-
Waterside	3,270,437	0%	-
Paddys 11	1,481,729	0%	-
Paddys 12	3,056,256	0%	-
Paddys 13	1,711,408	0%	-
Brown 5	1,206,136	0%	-
Brown 6	1,770,494	0%	-
Brown 7	4,054,075	0%	-
Trimble County 5	251,060	0%	-
Trimble County 6	250,927	0%	-
TC Pipeline	39,265	0%	-
Total Other Production Plant	20,674,502		-
Transmission Plant			
350.1 Land Rights	1,328,614	0%	-
352 Structures and Improvements	1,552,050	18%	279,369.07
353.1 Station Equipment	65,044,509	0%	-

354 Towers & Fixtures	17,988,442	56%	10,073,527.73
355 Poles & Fixtures	10,493,122	26%	2,728,211.62
356 Overhead Conductors and Devices	15,781,857	44%	6,944,017.02
357 Underground Conduit	296,505	0%	-
358 Underground Conductors & Devices	1,062,014	0%	-
Total Transmission Plant	113,547,113		20,025,125
Distribution Plant			
360.1 Land Rights	(126,985)	0	-
361 Structures and Improvements	4,271,725	0.18	768,910.43
362 Station Equipment	38,785,067	0.07	2,714,954.67
364 Poles Towers & Fixtures	45,059,307	0.48	21,628,467.18
365 Overhead Conductors and Devices	58,580,199	0.32	18,745,663.78
366 Underground Conduit	18,971,047	0.06	1,138,262.82
367 Underground Conductors & Devices	29,087,262	0.14	4,072,216.74
368 Line Transformers	41,798,461	0.13	5,433,799.98
369 Services	12,741,426	0.62	7,899,684.10
370 Meters	13,259,006	0.14	1,856,260.77
373 Street Lighting & Signal Systems	18,949,708	0.13	2,463,462.02
Total Distribution Plant	281,376,222		66,721,682
General Plant			
392.0 Transportation Equipment	10,924,780	-17%	(1,857,213)
394 Tool, Shop & Garage Equipment	665,248	0%	-
395 Laboratory Equipment	680,339	-9%	(61,230)
396 Power Operated Equipment	2,194,545	-28%	(614,473)
Total General Plant	14,464,912		(2,532,916)
Total Electric Reserve	1,235,730,945		165,493,726	13%

Louisville Gas and Electric Company
Estimated Removal Cost in Reserve
at December 2002

Property Group	Reserve Balance 12-31-02	Salv/Dep Ratio	Estimated Removal Cost
GAS PLANT			
INTANGIBLE PLANT	574,194	0%	-
UNDERGROUND STORAGE			
350.10 LAND	2,657	0%	-
350.20 RIGHTS OF WAY	17,227	0%	-
351.20 COMPRESSOR STATION STRUCTURES	612,216	19%	113,919.54
351.30 MEAS. & REG. STATION STRUCTS.	14,190	0%	-
351.40 OTHER STRUCTURES	702,549	36%	255,063.41
352.20 RESERVOIRS	435,216	0%	(4.04)
352.30 NONRECOVERABLE NATURAL GAS	6,498,004	0%	2.79
352.40 WELL DRILLING	2,284,122	54%	1,234,368.43
352.50 WELL EQUIPMENT	2,490,213	38%	939,950.73
353.00 LINES	5,303,771	13%	713,679.40
354.00 COMPRESSOR STATION EQUIPMENT	6,416,288	0%	12.78
355.00 MEAS. & REG. EQUIPMENT	241,547	0%	22.90
356.00 PURIFICATION EQUIPMENT	3,000,444	26%	765,652.11
357.00 OTHER EQUIPMENT	188,129	0%	2.64
TOTAL UNDERGROUND	28,206,572		4,022,671
TRANSMISSION PLANT			
365.20 RIGHTS OF WAY	184,549	0%	-
367.00 MAINS	10,781,829	49%	5,238,918.44
	10,966,378		5,238,918.44
DISTRIBUTION PLANT			
374.00 Land Rights	63,454	0%	-
375.10 CITY GATE CHECK STATION STRUCTS.	84,620	43%	36,456.99
375.20 OTHER DISTRIBUTION STRUCTURES	278,034	16%	44,944.73
376.00 MAINS	72,244,897	22%	15,616,723.17
378.00 MEAS. & REG. STATION EQUIP.-GEN.	1,714,716	7%	125,687.14
379.00 MEAS. & REG. STATION EQUIP.-CITY GT	1,009,276	0%	(6.28)
380.00 SERVICES	29,680,885	54%	16,072,643.62
381.00 METERS	5,556,038	7%	397,624.24
382.00 METER INSTALLATIONS	1,395,746	12%	170,171.88
383.00 HOUSE REGULATORS	1,442,672	7%	101,570.53
384.00 HOUSE REGULATOR INSTALLATIONS	413,586	0%	0.73
385.00 IND. MEAS. REG. & STATION EQUIPMEN	92,036	0%	(10.00)
387.00 OTHER EQUIPMENT	18,779	0%	(2.03)
TOTAL DISTRIBUTION	113,994,740		32,565,805
GENERAL PLANT			
392.10 TRANSPORTATION EQUIP-TRUCKS	2,136,820.64	0%	-
392.20 TRANSPORTATION EQUIP-TRAILERS	78,755	-13%	(10,257.04)
394.10 SHOP EQUIPMENT	787,585	-19%	(149,242.27)
395.00 LABORATORY EQUIPMENT	210,471	-8%	(17,182.08)
396.20 POWER OPERATED EQUIPMENT	1,817,977	-18%	(333,709.16)
TOTAL GENERAL PLANT	5,031,609		(510,391)
TOTAL GAS PLANT	158,773,493		41,317,003

Louisville Gas and Electric Company
Estimated Removal Cost in Reserve
at December 2002

Property Group	Reserve Balance 12-31-02	Salv/Dep Ratio	Estimated Removal Cost
COMMON PLANT			
GENERAL PLANT			
390.10 STRUCTS. & IMPROVES. - MISC.	14,643,039	10%	1,394,045.60
390.20 STRUCTS. & IMPROVES. - TRANSP.	582,428	10%	60,377.62
390.30 STRUCTS. & IMPROVES. - STORES	5,877,424	12%	690,342.93
390.40 STRUCTS. & IMPROVES. - OTHER	258,257	15%	39,606.55
390.60 STRUCTS. & IMPROVES. - MICROWAVE	75,498	12%	8,842.73
391.00 OFFICE EQUIPMENT - EXCL. COMPUTER	5,258,703	-4%	(190,421.33)
392.20 TRANSPORTATION EQUIP. - TRAILERS	25,213	-19%	(4,713.03)
393.00 STORES EQUIPMENT	301,474	-7%	(19,924.16)
394.20 GARAGE EQUIPMENT	399,478	12%	47,673.05
395.00 LAB EQUIPMENT	6,221	-13%	(803.81)
396.20 POWER OPERATED EQUIPMENT	266,994	-23%	(61,805.03)
397.00 COMMUNICATION EQUIPMENT	10,120,015	0%	(2.82)
398.00 MISC. EQUIPMENT	147,136	0%	-
TOTAL DEPREC. GENERAL PLANT	37,961,880		1,963,218.31
COMPUTER EQUIPMENT	9,559,023	0%	-
PC EQUIPMENT	7,038,487	0%	-
389.20 LAND RIGHTS	85,682	0%	-
391.1 TRANSP. CARS & TRUCKS	495,338	0%	-
	-	0%	-
TOTAL GENERAL PLANT	55,140,410		1,963,218
INTANGIBLE PLANT	18,101,954	0%	-
TOTAL COMMON PLANT IN SERVICE	**73,242,364**		**1,963,218**

Kentucky Utilities Company
Estimated Removal Cost in Reserve
at December 2002

Property Group	Reserve Balance 12-31-02	Salv/Dep Ratio	Estimated Removal Cost	
Intangible Plant				
302 Franchises and Consents	30,161			
303 Misc Intangible Plant	9,098,856			
Total Intangible Plant	9,129,016		-	
Steam Production Plant				
Brown Unit 1	31,175,389	22%	6,858,585.60	
Brown Unit 2	25,573,077	17%	4,347,423.02	
Brown Unit 3	81,080,583	13%	10,540,475.75	
Ghent Unit 1	100,224,747	10%	10,022,474.72	
Ghent Unit 2	101,658,765	19%	19,315,165.44	
Ghent Unit 3	175,352,501	12%	21,042,300.15	
Ghent Unit 4	141,254,946	10%	14,125,494.63	
Green River Units 1&2	19,587,149	48%	9,401,831.71	
Green River Unit 3	15,954,468	39%	6,222,242.60	
Green River Unit 4	26,883,951	25%	6,720,987.87	
Pineville Unit 3	2,036,242	32%	651,597.42	
Tyrone Unit 3	25,979,979	52%	13,509,589.09	
System Laboratory	618,402	0%	-	
Pollution Control Equipment	47,474,392	10%	4,747,439.19	
Total Steam Production Plant	794,854,593		127,505,607	
Hydraulic Production Plant				
Dix Dam	7,535,236	25%	1,883,809.03	
Lock # 7	788,668	54%	425,880.79	
Total Hydraulic Production Plant	8,323,904		2,309,689.82	
Other Production Plant				
Brown 5	1,052,014	0%	-	
Brown 6	4,200,846	0%	-	
Brown 7	4,501,716	0%	-	
Brown 8	7,443,528	0%	-	
Brown 9	10,106,714	0%	-	
Brown 9 Pipeline	2,230,833	0%	-	
Brown 10	6,645,682	0%	-	
Brown 11	7,025,522	0%	-	
Haefling	4,284,007	0%	-	
Paddys 13	1,498,867	0%	-	
TC 5	613,822	0%	-	
TC 6	613,501	0%	-	
TC Pipeline	95,855	0%	-	
Total Other Production Plant	50,312,905		-	
Transmission Plant				
350.1 Land Rights	13,791,158	0%	-	
352 Structures and Improvements	3,753,177	45%	1,688,929.50	
353.1 Station Equipment	48,523,476	14%	6,793,286.66	
353.2 Syst Control/Microwave Equip	12,319,025	19%	2,340,614.82	
354 Towers & Fixtures	35,979,699	55%	19,788,834.20	
355 Poles & Fixtures	50,576,279	59%	29,840,004.41	
356 Overhead Conductors and Devices	83,709,013	53%	44,365,776.65	
357 Underground Conduit	98,612	11%	10,847.28	
358 Underground Conductors & Devices	645,771	8%	51,661.68	
Total Transmission Plant	249,396,209		104,879,955	
Distribution Plant				
360.1 Land Rights	951,241	0	-	
361 Structures and Improvements	1,196,111	0.14	167,455.57	
362 Station Equipment	24,988,144	0.13	3,248,458.72	
364 Poles Towers & Fixtures	83,400,337	0.44	36,696,148.39	
365 Overhead Conductors and Devices	86,113,585	0.46	39,612,249.22	
366 Underground Conduit	595,503	0.16	95,280.46	
367 Underground Conductors & Devices	10,039,190	0.11	1,104,310.92	
368 Line Transformers	74,145,010	0.13	9,638,851.32	
369 Services	40,675,621	0.43	17,490,516.97	
370 Meters	23,665,574	0.15	3,549,836.06	
371 Installations on Customer Premises	9,433,568	0	-	
373 Street Lighting & Signal Systems	16,473,489	0.14	2,306,288.50	
Total Distribution Plant	371,679,812		113,909,396	
General Plant				
389.1 Land Rights	154,183	0%	-	
390.1 Structures & Improvements	7,705,611	0%	-	
391.1 Office Furniture & Equipment	15,345,624	0%	-	
392.0 Transportation Equipment	20,582,770	0%	-	
393 Stores Equipment	253,419	-12%	(30,410)	
394 Tool, Shop & Garage Equipment	1,130,302	-8%	(90,424)	
395 Laboratory Equipment	1,219,542	-5%	(60,977)	
396 Power Operated Equipment	117,318	-61%	(71,564)	
397 Communication Equipment	2,718,367	0%	-	
398 Misc Equipment	258,333	0%	-	
Total General Plant	49,485,369		(253,375)	
Total Reserve	1,533,181,808		348,351,273	23%
RWIP	3476144.26			
	1,536,657,952			