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MAR 2 3 2004

PUBLIC SERVICE

March 22, 2004

Thomas M. Dorman, Esq. Executive Director Kentucky Public Service Commission 211 Sower Boulevard Frankfort, Kentucky 40602

Re: <u>Case No. 2003-00433 and 2003-00434</u>

Dear Mr. Dorman:

Please find enclosed the original and twelve copies each of the following: 1) Direct Testimony and Exhibits of Lane Kollen on behalf of Kentucky Industrial Utility Customers, Inc., 3) Direct Testimony and Exhibits of Richard A. Baudino on behalf of Kentucky Industrial Utility Customers, Inc.; and 3) Direct Testimony and Exhibits of Stephen J. Baron on behalf of Kentucky Industrial Utility Customers, Inc. filed in the above-referenced matters.

By copy of this letter, all parties listed on the attached Certificate of Service been served. Please place this document of file.

Very Truly Yours,

mine hit

Michael L. Kurtz, Esq. BOEHM, KURTZ & LOWRY

MLKkew Attachment CC:

Certificate of Service Richard Raff, Esq.

VIA OVERNIGHT MAIL

CERTIFICATE OF SERVICE

I hereby certify that a copy of the foregoing was served by mailing a true and correct copy, by regular U.S. mail (unless otherwise noted) to all parties on the 22^{nd} day of March, 2004.

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Michael L. Kurtz, Esq.



COMMONWEALTH OF KENTUCKY

MAR 2 3 2004

BEFORE THE PUBLIC SERVICE COMMISSION

PUBLIC SERVICE COMMISSION

IN THE MATTER OF:

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

DIRECT TESTIMONY

AND EXHIBITS

OF

LANE KOLLEN

ON BEHALF OF THE

KENTUCKY INDUSTRIAL UTILITY CUSTOMERS, INC.

J. KENNEDY AND ASSOCIATES, INC. ROSWELL, GEORGIA

MARCH 2004

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

IN THE MATTER OF:

)	
)	CASE NO.
)	2003-00434
))

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COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

IN THE MATTER OF:

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

DIRECT TESTIMONY OF LANE KOLLEN

I. QUALIFICATIONS AND SUMMARY

	Q.	Please state your name and business address.
2		
3	A.	My name is Lane Kollen. My business address is J. Kennedy and Associates, Inc.
4		("Kennedy and Associates"), 570 Colonial Park Drive, Suite 305, Roswell, Georgia
5		30075.
6		
7	Q.	What is your occupation and by whom are you employed?
	<u>ب</u>	what is your occupation and by whom are you on program
8	χ.	what is your occupation and by whom are you superyour
8 9	A.	I am a utility rate and planning consultant holding the position of Vice President and
	-	
9	-	I am a utility rate and planning consultant holding the position of Vice President and

2	A.	I earned a Bachelor of Business Administration in Accounting degree from the
3		University of Toledo. I also earned a Master of Business Administration degree from
4		the University of Toledo. I am a Certified Public Accountant, with a practice license,
5		and a Certified Management Accountant.
6		
7		I have been an active participant in the utility industry for more than twenty-five years,
8		both as an employee and as a consultant. Since 1986, I have been a consultant with
9		Kennedy and Associates, providing services to state government agencies and large
10		consumers of utility services in the ratemaking, financial, tax, accounting, and
11		management areas. From 1983 to 1986, I was a consultant with Energy Management
12		Associates, providing services to investor and consumer owned utility companies. From
13		1976 to 1983, I was employed by The Toledo Edison Company in a series of positions
14		encompassing accounting, tax, financial, and planning functions.
15		
16		I have appeared as an expert witness on accounting, finance, ratemaking, and planning
17		issues before regulatory commissions and courts at the federal and state levels on more
18		than one hundred occasions. I have developed and presented papers at industry
19		conferences on ratemaking, accounting, and tax issues.
20		

1

1		I have testified before the Kentucky Public Service Commission on numerous occasions,
2		including the two most recent Louisville Gas and Electric Company ("LG&E" or
3		"Company") base rate cases, Case Nos. 90-158 and 98-474; the most recent Kentucky
4		Utilities Company ("KU" or "Company") base rate case, 98-426; the merger proceeding,
5		Case No. 97-300; numerous LG&E and KU environmental cost recovery ("ECR") and
6		fuel adjustment clause ("FAC") proceedings, and proceedings involving Kentucky
7		Power Company ("KPC" or "Company") and Big Rivers Electric Corporation. Most
8		recently, I filed testimony before the Commission in the LG&E and KU Earnings
9		Sharing Mechanism ("ESM") proceedings, Case Nos. 2003-0335 and 2003-0334,
10		respectively. My qualifications and regulatory appearances are further detailed in my
11		Exhibit(LK-1).
12		
13	Q.	On whose behalf are you testifying?
14		
15	A.	I am testifying on behalf of the Kentucky Industrial Utility Customers, Inc. ("KIUC"), a
16		group a large users taking electric service on the KU system.
17		
18	Q.	What is the purpose of your testimony?
19		

1	A.	The purpose of my testimony is to address the revenue requirement requests of KU for
2		electric service, to address the continuation or termination of the ESMs as an alternative
3		form of regulation, and to address the change in base rates that should occur upon the
4		expiration of the merger savings surcredit and the expiration of the VDT surcredit.
5		
6	Q.	Please summarize your testimony.
7		
8	A.	I recommend that the Commission reduce the Company's requested electric base rate
9		increase for the issues listed and amounts quantified on the following table. I address
10		each of these issues, except for the return on common equity, which Mr. Baudino
11		addresses, and quantify the effects of each issue on the revenue requirements.
12		

Kentucky Utilities Company Summary of KIUC Revenue Requirement Iss	ues
Issues	\$000
Operating Income Adjustments	
Unbilled Revenues	-\$675
Imputed Lost Revenues - NAS Rate Switching	\$1,899
O&M - Labor Savings VDT	\$6,121
O&M - Pension and OPEB	\$3,015
O&M - Amortization of Ice Storm Costs	\$1,319
O&M - OMU NOx Expense	\$1,960
Depreciation - Gross Salvage and Cost of Removal	\$19,817
Depreciation - Post Test Year Plant Additions	\$5,700
Rate of Return Adjustments	
Return on Common Equity	\$29,538
Additional Annualized Reduction	\$68,694
KU Claimed Revenue Deficiency	-\$58,254
KIUC Adjusted Revenue Surplus	\$10,440

1	
2	
3	I also recommend that the Company's ESM be discontinued. I recommend that the
4	ESM surcharge based on the test year 2003 be discontinued on the effective date of any
5	electric base rate increase authorized in this proceeding. The Commission should
6	consider the ESM terminated by virtue of the Company's filing of its electric base rate
7	increase request in December 2003.
8	
9	The Commission should not allow two alternative and mutually exclusive forms of
10	regulation to remain in effect simultaneously. The simultaneous operation of two
11	ratemaking paradigms could not have been envisioned by the Commission when it
12	offered the Company the choice of the ESM or continued traditional regulation in Case
13	No. 98-426. It cannot possibly meet the statutory requirement for just and reasonable
14	rates.
15	
16	The simultaneous operation of two ratemaking paradigms will result in excessive rates
17	through rate pancaking and the simultaneous imposition of two separate rate increases.
18	Under both ratemaking paradigms, base rates are set prospectively. The ESM was not
19	established as a historic test year true-up mechanism, despite the Company's position to
20	the contrary.

1	
2	If the Commission does not terminate the ESM surcharge upon the effective date of any
3	rate increase from this proceeding, and continues the ESM, then the Commission should
4	annualize the rate increase for the ESM 2004 test year in the same manner that it
5	annualized the rate reduction for the ESM 2000 test year when it was initially
6	implemented.
7	
8	In addition, I recommend that the Commission specifically order in this proceeding that
9	base rates be reduced by the amounts included in the revenue requirement for the merger
10	savings surcredit upon its expiration in 2008 and for the VDT surcredit upon its
11	expiration in 2006. Base rates pursuant to the ESM would have been adjusted annually
12	to reflect the removal of these amounts; however, base rates determined in this
13	proceeding will not be adjusted downward upon the expiration of these surcredit
14	amounts unless the Commission specifically directs the Company to do so.
15	
16	Finally, I recommend that the Commission adopt a System Sales Clause to share off-
17	system sales margins between the Company and ratepayers patterned after the System
18	Sales Clause currently in effect for Kentucky Power Company. The System Sales
19	Clause would share 50% to the Company and 50% to the ratepayers the net change in
20	offsystem sales margins compared to the margin reflected in base rates.

1		II. REVENUE REQUIREMENT
2		
3	<u>Unbil</u>	led Revenues
4		
5	Q.	Please describe the Company's adjustments to remove unbilled revenues for
6		ratemaking purposes.
7		
8	A.	The Company has increased electric operating revenues by \$0.675 million to remove
9		unbilled revenues for ratemaking purposes from its per books test year revenues. The
10		Company's adjustment converts the Company's revenue accounting from the unbilled
11		revenues methodology it actually uses for per books accounting purposes to a meters
12		read methodology for ratemaking purposes.
13		
14	Q.	Please describe the difference between the unbilled revenues and meters read
15		methodologies for recognizing revenues.
16		
17	A.	The Company recognizes actual revenues on its accounting books based upon the
18		unbilled revenues methodology. The unbilled revenues methodology matches the
19		revenues in the month with the service provided and the costs incurred to provide that
20		service. The unbilled revenues methodology adjusts the billed revenues in the month to

1		properly recognize the revenues actually earned in the month based on the electricity
2		delivered. It removes the effects on revenues of delays in meter reading and billing due
3		to the fact that all meters are not read and bills issued on the last day of the month in
4		which the service was provided. Each month, the Company quantifies and accrues the
5		unbilled revenues for that month and reverses the accrual for the preceding month. The
6		reason the accrual for the preceding month is reversed is that the preceding month
7		unbilled revenues actually are billed in the current month. Unbilled revenues may be
8		positive or negative.
9		
10		In contrast to the unbilled revenues methodology, the meters read methodology
11		recognizes revenues on a lagged basis only after meters are read and bills are issued.
12		There is no match in any given month between the revenues recognized and the service
13		provided because a portion of the billings in the month are due to service provided in the
14		preceding month and do not include billings for all the service provided in the current
15		month.
16		
17	Q.	Has the Commission previously addressed the issue of whether the Company's
18		revenues should be adjusted from the unbilled revenues methodology actually used
19		by the Company to the meters read methodology for ratemaking purposes?

20

1	A.	No. The Commission has not specifically addressed the issue of whether the Company
2		should be allowed to restate its revenues for ratemaking purposes to a methodology the
3		Company no longer uses. However, in Case No. 8624, the Commission did not adopt
4		an adjustment proposed by the Attorney General to restate revenues from the meters
5		read methodology then used by KU for both accounting and ratemaking purposes to the
6		unbilled revenues methodology for ratemaking purposes. Since Case No. 8624, the
7		Company has changed its accounting for revenues to reflect the unbilled revenues
8		methodology.
9		
10	Q.	Should the Commission accept the Company's adjustment to restate its per books
10	٧·	
11	Q.	accounting revenues to utilize the meters read methodology?
	ų.	
11	Q .	
11 12	-	accounting revenues to utilize the meters read methodology?
11 12 13	-	accounting revenues to utilize the meters read methodology? No. There is no principled basis to accept this adjustment. First, the adjustment does not comport with reality. Second, it creates an inappropriate difference between the
11 12 13 14	-	accounting revenues to utilize the meters read methodology? No. There is no principled basis to accept this adjustment. First, the adjustment does
11 12 13 14 15	-	accounting revenues to utilize the meters read methodology? No. There is no principled basis to accept this adjustment. First, the adjustment does not comport with reality. Second, it creates an inappropriate difference between the revenues for ratemaking and accounting. Third, it creates a ratemaking mismatch
11 12 13 14 15 16	-	accounting revenues to utilize the meters read methodology? No. There is no principled basis to accept this adjustment. First, the adjustment does not comport with reality. Second, it creates an inappropriate difference between the revenues for ratemaking and accounting. Third, it creates a ratemaking mismatch between the revenues that should be and actually were recognized compared to the
 11 12 13 14 15 16 17 	A.	accounting revenues to utilize the meters read methodology? No. There is no principled basis to accept this adjustment. First, the adjustment does not comport with reality. Second, it creates an inappropriate difference between the revenues for ratemaking and accounting. Third, it creates a ratemaking mismatch between the revenues that should be and actually were recognized compared to the

1	Q.	Please describe this adjustment proposed by the Company.
2		
3	A.	The Company proposes to reduce revenues by \$1.899 million to reflect its estimate of
4		the effects of a customer, North American Stainless ("NAS"), switching from a special
5		contract rate to KU's proposed Non-Conforming Load Service Rate (NCLS) with
6		interruptible service.
7		
8	Q.	Should the Commission adopt this proposed adjustment?
9		
10	A.	No. There has been no switching and there has been no loss of revenue. The
11		Commission has a pending case, Case No. 2003-396, in which it will consider this
12		proposed transfer, along with the potential effect on both NAS and KU. It is my
13		understanding that there is significant disagreement between NAS and KU over the
14		issues, including the ability of NAS to accept the terms of the proposed NCLS tariff,
15		how NAS will respond depending on the Commission's decision in that case, and the
16		resulting revenue effect on NAS and KU.
17		
18		At this time, any quantification of the revenue effect is speculative and effectively would
19		prejudge the outcome of another pending proceeding. The effects of the Commission's
20		decision on the revenues from NAS to KU, whether an increase or a decrease and how

1		much, can be addressed in KU's next base rate proceeding along with all other future
2		changes in KU's revenue requirement.
3		
4	<u>Oper</u>	ation and Maintenance Expense – Failure to Achieve Labor Savings from VDT
5		
6	Q.	Please describe the premise underlying the incurrence by the Company of \$56.300
7		million in severance costs related to its workforce reduction program initiated in
8		the first quarter 2001.
9		
10	A.	The premise underlying the incurrence of this huge cost was that the Company would
11		achieve savings by reducing the number of employees. Some positions were to be
12		eliminated permanently, some were to be filled with lower cost employees, and some
13		were to be eliminated permanently but effectively filled through the use of contractors.
14		The Company projected that savings over five years would exceed the costs of the
15		employee buyout.
16		
17	Q.	Please describe the ratemaking treatment of the employee buyout costs and the
18		projected savings.
19		

1	Α.	In Case No. 2001-169, the Company sought to defer the entirety of the employee buyout
2		costs and to amortize the deferred debits as an expense recoverable through its annual
3		Earnings Sharing Mechanism filings. Pursuant to a settlement of the ratemaking
4		treatment of these costs and savings, along with other issues in other proceedings, the
5		Company was allowed to defer the employee buyout costs and amortize them over five
6		years. The Company agreed to provide 50% of the projected savings to ratepayers
7		through a value delivery ("VDT") surcredit. In addition, the Company was allowed to
8		include 50% of the projected savings as an expense in its annual ESM filings in 2001
9		and 2002 and in any "successor earnings sharing ratemaking mechanism."
10		
11	Q.	What was the effect of this ratemaking treatment in the ESM proceedings?
12		
13		
	А.	In 2002 and 2003, the Company was below the lower threshold of the ESM return on
14	A.	In 2002 and 2003, the Company was below the lower threshold of the ESM return on equity deadband. As such, it was or will be able to recover from ratepayers at least 40%
14 15	Α.	
	A.	equity deadband. As such, it was or will be able to recover from ratepayers at least 40%
15	A.	equity deadband. As such, it was or will be able to recover from ratepayers at least 40% of the VDT amortization expense, at least 40% of the savings amounts that were flowed
15 16	A.	equity deadband. As such, it was or will be able to recover from ratepayers at least 40% of the VDT amortization expense, at least 40% of the savings amounts that were flowed through the VDT surcredit, and at least 40% of the retained savings it included as an
15 16 17	А. Q .	equity deadband. As such, it was or will be able to recover from ratepayers at least 40% of the VDT amortization expense, at least 40% of the savings amounts that were flowed through the VDT surcredit, and at least 40% of the retained savings it included as an

1	A.	The Company has included the entirety of the VDT amortization expense, 100% of the
2		savings amounts that were flowed through the VDT surcredit, and 100% of the retained
3		savings as an expense adjustment, which it has included as Adjustment 23, reflected on
4		Rives Exhibit 1 Reference Schedule 1.20. The Company has included \$11.500 million
5		for the VDT amortization, \$1.930 million for the VDT surcredit, and \$2.895 million for
6		the retained savings as an expense adjustment. In total, the Company has included
7		\$16.325 million for the workforce reduction costs in its revenue requirement.
8		
9	Q.	What labor savings amounts actually were reflected in the Company's filing
10		compared to the costs it incurred in 2000, the year prior to the implementation of
11		the VDT?
11 12		the VDT?
	A.	the VDT? The Company claims that it is unable to quantify the labor savings. However, it was
12	A.	
12 13	A.	The Company claims that it is unable to quantify the labor savings. However, it was
12 13 14	A.	The Company claims that it is unable to quantify the labor savings. However, it was able to quantify its direct labor costs in total and separated between expense and capital
12 13 14 15	A.	The Company claims that it is unable to quantify the labor savings. However, it was able to quantify its direct labor costs in total and separated between expense and capital in response to PSC 1-23(c). In the test year, its total direct labor, including the costs
12 13 14 15 16	A.	The Company claims that it is unable to quantify the labor savings. However, it was able to quantify its direct labor costs in total and separated between expense and capital in response to PSC 1-23(c). In the test year, its total direct labor, including the costs charged from Servco, the LG&E Energy mutual services company, was \$77.779 million.
12 13 14 15 16 17	A.	The Company claims that it is unable to quantify the labor savings. However, it was able to quantify its direct labor costs in total and separated between expense and capital in response to PSC 1-23(c). In the test year, its total direct labor, including the costs charged from Servco, the LG&E Energy mutual services company, was \$77.779 million. In 2000, the year prior to the workforce reduction program, its total direct labor was

1		savings (\$2.154 million Kentucky jurisdictional). I have replicated the Company's
2		response to PSC 1-23(c) as my Exhibit (LK-2).
3		
4	Q.	How do the actual labor cost savings in the test year from 2000 compare to the
5		costs of the workforce reduction included in the revenue requirement?
6		
7	A.	The were no savings in total direct labor costs. The expense savings represents only
8		13% of the workforce reduction costs included in the revenue requirement by the
9		Company in this proceeding.
10		
11	Q.	Does this comparison include all the costs that have been incurred in the test year
11 12	Q.	Does this comparison include all the costs that have been incurred in the test year compared to the year before the workforce reduction?
	Q.	-
12	Q. A.	-
12 13		compared to the year before the workforce reduction?
12 13 14		compared to the year before the workforce reduction? No. It does not include any increases in contractor costs incurred by the Company due
12 13 14 15		compared to the year before the workforce reduction? No. It does not include any increases in contractor costs incurred by the Company due to reductions in employees. In addition, it does not include the related costs of pensions,
12 13 14 15 16		compared to the year before the workforce reduction? No. It does not include any increases in contractor costs incurred by the Company due to reductions in employees. In addition, it does not include the related costs of pensions, other postretirement benefits, or any other overhead costs, all of which would have or

Q.	Do you recommend that the Commission disallow a portion of the O&M expense
	due to the Company's failure actually to achieve savings that equaled or exceeded
	the cost of the employee buyout?
A.	Yes. I recommend that the Commission disallow at least 50% of the net harm to
	ratepayers from the Company's failure to achieve these labor savings. The disallowance
	at 50% is \$6.121 million. I have computed the net harm to ratepayers as \$12.241
	million, consisting of the total \$16.325 million included in the filing to recover these
	costs less the \$1.930 million returned to ratepayers through the VDT surcredit, and less
	the \$2.154 million (KY jurisdictional) in direct labor expense savings reflected in the
	filing.
	The Commission has an obligation to ensure that rates are just and reasonable. It is not
	just and reasonable for ratepayers to bear the burden not only of the costs of the
	workforce reduction, but also the imputed savings retained by shareholders, the sum of
	which are substantially in excess of the direct labor savings actually achieved. It would
	be reasonable for the Commission to disallow the entirety of the workforce reduction
	costs included that exceed the direct labor achieved savings.

1	<u>Post '</u>	Test Year Adjustment to Increase Pension and Post Retirement Benefit Expense
2		
3	Q.	Please describe the Company's request to increase pension and post-retirement
4		benefit expense.
5		
6	A.	The Company proposes a selective post test year adjustment to increase its pension and
7		post-retirement benefit expense to projected 2004 levels. These projections are
8		preliminary estimates based upon computations provided by Mercer prior to the filing of
9		the Company's case. However, the actual pension and postretirement benefit expense
10		booked in 2004 will be based, in part, upon actual December 31, 2003 plan assets and
11		obligations, which were not available and therefore, could not be known and measurable
12		at the date the Company prepared its rate case filing, let alone at the date it was actually
13		filed.
14		
15	Q.	Please describe the basis for your conclusion that the projections relied upon by the
16		Company were preliminary estimates and are not known and measurable at the
17		date the Company prepared its rate case filing.
18		
19	A.	The Company's proforma adjustment relies upon certain "disclosure statements," which
20		Mercer prepared prior to December 31, 2003. The Company has not yet received an

1	actuarial study from Mercer for 2004, according to its responses to PSC 2-16(e) and
2	KIUC 1-88. Indeed, Mercer could not have prepared or released such an actuarial study
3	because actual December 31, 2003 information was not yet available for that purpose.
4	Thus, the disclosure statements, of necessity, were predicated upon estimates in lieu of
5	actual amounts for the December 31, 2003 valuations. The actual December 31, 2003
6	valuation ultimately will be determined by Mercer to compute the Company's 2004
7	pension and postretirement benefit expense, not the estimates it prepared based on
8	December 31, 2003 projections for the Company's rate case filing. It isn't at all clear
9	what assumptions Mercer made on behalf of the Company to project the December 31,
10	2003 valuations for this purpose. Nevertheless, it is clear that the Company will book its
11	2004 pension and post retirement benefit expense based upon actual December 31, 2003
12	valuations, not the estimates prepared by Mercer for use by the Company in its rate case
13	filing.
14	
15	The Company was asked to provide the actuarial report relied on for its adjustment in
16	PSC 2-16(e) and KIUC 1-88. The Company's response to PSC 2-16(e) stated "Please
17	see that attached actuarial reports from Mercer for the fiscal year ending December 31,
18	2002. The actuarial reports from Mercer for the fiscal year ending December 31, 2003
19	are not yet available." However, that representation is not correct. A reading of the
20	titles of the actuarial reports provided by LG&E in its response indicate that these were

1		the actuarial reports relied upon for the Company's pension and postretirement benefit
2		expense actually booked in calendar year 2003. The titles of the actuarial reports for
3		LG&E are as follows, with all indicating that they are for the year 2003, not 2002:
4		
5 6 7 8		• LG&E Energy Corp. Retirement Plan; Revised Actuarial Valuation Report As of January 1, 2003 for the Plan Year and Taxable Year Ending December 31, 2003 Including FAS 87 Expense for the Fiscal Year Ending December 31, 2003 (dated October 2003).
9 10 11 12 13		• Louisville Gas and Electric Company Bargaining Employees' Retirement Plan; Actuarial Valuation Report As of January 1, 2003 for the Plan Year and Taxable Year Ending December 31, 2003 Including FAS 87 Expense for the Fiscal Year Ending December 31, 2003 (dated September 2003).
14 15 16 17 18		• LG&E Energy Corp. Postretirement Benefit Valuation Report Under FAS 106; Expense for the Fiscal Year Ending December 31, 2003 (dated December 2003).
19 20	Q.	Should the Commission accept the Company's proforma adjustment to increase
21		pension and postretirement benefit expense?
22		
23	A.	No. First, this adjustment represents a selective post test year adjustment to increase the
24		Company's revenue requirement. As such, it is one-sided and inequitable. It violates
25		the test year principle of consistent quantification of all components of the revenue
26		requirement. If the Commission accepts this post test year adjustment, then it should
27		also make other post test year adjustments. For example, it could increase revenues to
28		reflect expected customer growth in 2004. It could project increased off-system sales

1		revenues due to the significant capacity additions when the Trimble County gas turbines
2		commence operation in 2004. It could project reduced O&M expense for 2004 due to
3		the substantial nationwide increases in productivity that exceed inflation as measured by
4		the Bureau of Labor Statistics.
5		
6		Second, the estimates relied on by the Company are not known and measurable. They
7		do not reflect actual valuations as of December 31, 2003, consistent with the manner in
8		which the Company relied on the Mercer actuarial reports for 2003. Third, they are
9		estimates that cannot be verified based on the schedules provided in response to
10		discovery.
11		
12	<u>Noni</u>	ecurring Expenses and Credits
13		
14	Q.	Please describe the adjustment the Company made to defer and amortize the costs
15		associated with the ice storm during the test year.
16		
17	A.	The Company reduced expense by \$5.277 million to reflect a five-year amortization of
18		the Company's costs net of insurance recovery rather than by \$6.597 million to remove
19		this nonrecurring cost altogether, thus including \$1.319 million in amortization expense
20		in the revenue requirement for this cost.

2 Q. Should the Commission allow the Company to defer and amortize the ice storm 3 amount?

4

No. This nonrecurring amount was subject to the ESM for the 2003 test year. As such, 5 A. 6 it is necessary to remove this nonrecurring amount in its entirety to set base rates 7 prospectively. It would be inappropriate to allow the Company to recover these costs 8 through the ESM surcharge and also the through base rates set in this proceeding. It 9 should be noted that LG&E simply removed two nonrecurring credits to expense (for 10 LG&E corporate office lease expense and the Cane Run insurance recovery) that 11 occurred during the test year. As I noted in my LG&E testimony, I agree with the 12 removal of these nonrecurring credits, but only if all nonrecurring costs are treated 13 consistently for each Company and between the two Companies.

14

15 OMU NOx Expense

16

17 Q. Please describe the Company's request to include an adjustment to increase 18 operating expenses for the OMU NOx compliance.

A. The Company's has included a selected post test year adjustment to increase purchased
 power expenses by \$1.960 million for costs associated with OMU NOx compliance.

1		These costs are related to OMU debt service that KU must commence paying on July 1,
2		2004 and are estimated.
3		
4	Q.	Should the Commission allow this post test year expense in the revenue
5		requirement?
6		
7	А.	No. First, this is a selective post test year adjustment with no consideration of other test
8		year revenue requirement components that could reduce the revenue requirement.
9		Second, the Company could seek to have the Commission include such costs in its
10		environmental compliance plan and recover them through the ECR once they are known
11		and measurable.
12		
13	Depre	eciation Expense – Gross Salvage and Cost of Removal
14		
15	Q.	Please describe how net salvage on interim retirements is reflected in the
16		Company's proposed depreciation rates.
17		
18	А.	The Company includes net salvage on interim retirements as an increase to its proposed
19		depreciation rates if the property grouping has projected net negative salvage (cost of
20		removal exceeds gross salvage proceeds) and as a reduction to its proposed depreciation

- rates if the property grouping has projected net salvage (gross salvage proceeds exceed
 cost of removal).
- 3

In its depreciation study, the Company multiplies the net negative salvage rate against the interim retirement rate to determine the estimated net future salvage on estimated interim retirements. The Company then adds the estimated net future salvage on estimated interim retirements to the estimated net terminal salvage in order to compute the total net salvage rate. These computations are detailed on Table 2-a in Section 2 of the AUS depreciation study. I have replicated Table 2-a as my Exhibit__(LK-3).

10

11 The total net salvage rates from Table 2-a are multiplied by the original plant in service 12 amounts to compute the net salvage dollars for each property grouping. The net salvage 13 dollars are in turn added to the original plant in service amounts to compute the 14 depreciation expense and depreciation rate based on the average remaining life for the 15 property grouping. These latter computations are detailed on Table 2 in Section 2 of the 16 AUS depreciation study. I have replicated Table 2 as my Exhibit__(LK-4).

17

Q. Please describe the methodology utilized by the Company to compute the net
 salvage on interim retirements included in its proposed depreciation rates.

1 The AUS depreciation study analyzed historic gross salvage and historic cost of removal A. 2 by FERC plant account. The AUS analyses are detailed in Section 7 of the study and 3 were performed by FERC plant account based upon actual historic data from the 4 Company's property accounting records. 5 6 For gross salvage, the AUS depreciation study computed 3 year rolling bands, and from 7 that data, computed the average actual historic gross salvage rate, and computed a 20-8 year trend rate, a 15-year trend rate, a 10-year trend rate, and a 5-year trend rate. In lieu 9 of the average actual historic gross salvage rate, the AUS depreciation study then simply 10 utilized the 5-year trend rate as the gross salvage rate against which it would net the 11 proposed cost of removal rate. For some FERC plant accounts, the gross salvage rate 12 derived by AUS using this methodology actually is negative, meaning that gross salvage 13 is represented in the proposed depreciation rates as an additional cost of removal. 14 15 For cost of removal, the AUS depreciation study utilized the average of the actual data 16 for the 20-year period, but then escalated the historic average to the midpoint of the average remaining service life by a projected annual inflation factor of 2.75%. This 17 18 methodology had the effect of significantly increasing the cost of removal, and thus, the

depreciation rates, for most property groupings. For some FERC plant accounts, the

19

1		cost of removal rate was increased by several fold compared to the actual historic data
2		for cost of removal.
3		
4	Q.	Should the Commission utilize the 5-year trend for gross salvage on interim
5		retirements?
6		
7	A.	No. The Commission should utilize the average of the actual historic data. First, the
8		actual data correctly establishes the relationship between gross salvage and interim
9		retirements. There is no reason to assume that this known and measurable relationship
10		will change in the future.
11		
12		Second, the depreciation study substitutes a percentage trend for the actual gross salvage
13		rate. Aside from the fact that the study utilizes the lowest percentage trend for the gross
14		salvage rate, a problem in and of itself, a trend is itself meaningless and inappropriate to
15		apply to estimated interim retirements.
16		
17	Q.	Should the Commission adjust the actual historic cost of removal rate for projected
18		inflation?
19	A.	No. The Commission should utilize the average of the historic data. The historic data
20		already reflects labor escalation in the year of the interim retirement compared to the

1 vintage original plant cost of the retirement. As such, in future years, the same relationship is likely to hold as older vintage plant is retired. The Company has offered 2 no evidence to demonstrate that the historic relationship will not hold prospectively. 3 4 5 The only rationale offered by the Company for this inflation factor is that labor costs will increase in the future. Yet inflation in labor costs already is reflected in the historic 6 cost of removal compared to the older vintage plant that was retired. In the past, the 7 labor costs included in the historic cost of removal also have increased due to inflation. 8 9 The AUS study utilizes the current cost of removal in those historic years divided by the 10 older vintage plant dollars that were retired in order to compute the cost of removal 11 percentage for that year. As such, the effects of inflation already are reflected in the 12 actual historic data. The Company's proposal to further increase the cost of removal double counts the effects of inflation by adding more inflation to the inflation already 13 14 reflected in the actual historic data. The Commission should reject this methodology. 15 16 In addition, the Company's application of an inflation rate to the historic cost of removal 17 represents a significant post test year adjustment, reaching forward many years into the 18 future based on the average remaining service life of the property grouping. As I 19 subsequently discuss in conjunction with the Company's inclusion of post test year NOx 20 compliance plant additions, the Commission in the past has rejected attempts to include

post test year costs on a selective basis such as this. The Commission should reject this methodology.

3

1

2

Q. Have you quantified the effects on the depreciation rates and the resulting
depreciation expense of using the actual historic gross salvage and cost of removal
rates on interim retirements (for electric production) and retirements (for electric
non-production plant accounts)?

8

Yes. The effect on the depreciation rates and on test year depreciation expense is 9 Α. 10 summarized on my Exhibit (LK-5). For electric production, I first corrected the net 11 salvage rates for interim retirements on the spreadsheet underlying Table 2-a. I used the resulting interim retirement percentages from the corrected Table 2-a in the spreadsheet 12 underlying Table 2 to recompute the depreciation rates by FERC production plant 13 account. In the next step of the computation, I used another spreadsheet provided by the 14 Company to recompute the depreciation rates by production plant location using the 15 recomputed depreciation rates for the production FERC plant accounts. To correct the 16 net salvage rates on the spreadsheet underlying Table 2-a, I simply used the FERC plant 17 account historic net salvage rates from Section 7 of the depreciation study. In the final 18 step, I computed annualized depreciation expense and the proforma depreciation 19 20 expense adjustment utilizing the spreadsheet provided by the Company for its

1		Adjustment 1.11, substituting the corrected electric depreciation rates with the net
2		salvage rates properly computed for the Company's proposed depreciation rates.
3		
4		For electric nonproduction plant, I utilized the depreciation rates provided by the
5		Company in response to PSC 2-24(b), which recomputed the depreciation rates using the
6		FERC plant historic net salvage rates from Section 7 of the depreciation study. To
7		compute annualized depreciation expense and the proforma depreciation expense
8		adjustment, I utilized the spreadsheet provided by the Company for its Adjustment 14,
9		Rives Exhibit 1 Reference Schedule 1.11, substituting the corrected nonproduction plant
10		depreciation rates reflecting the actual historic net salvage rates for the Company's
11		proposed rates. Although I used the Company's computation of these depreciation rates
12		for nonproduction plant, the results suggest that the Company's computations or data
13		may be in error, at least for some accounts, such as FERC plant accounts 353.1, 356,
14		362, 364, 365, and 367.
15		·
16	Q.	The effect on the depreciation rates reflected on your Exhibit(LK-5) for electric
17		production plant does not agree with the effect quantified by the Company in
18		response to PSC 2-24(b). Please explain why.
19	A.	The effects quantified by the Company for electric production plant are erroneous.
20		Removing the inflation factor from the cost of removal as requested by the Staff should

1		have resulted in lower net negative salvage for certain production FERC plant accounts,
2		and thus, lower depreciation rates for those plant accounts. Instead, the depreciation
3		rates increased for those accounts. The error appears to be due a change in methodology
4		compared to the depreciation study itself. In the response, the Company applied the
5		actual net salvage rate percentages to the original cost of the assets rather than the
6		interim retirements as it did in the AUS depreciation study. This methodological error
7		in the response to PSC 2-24(b) had the effect of improperly increasing the net salvage
8		reflected in the resulting depreciation rates.
9		
10	Depr	<u>eciation Expense – Post Test Year Plant Additions</u>
11		
12	Q.	Did the Company reflect future plant additions in its proposed electric
13		depreciation rates?
14		
15	А.	Yes. The Company included plant additions for NOx emission compliance that it
16		projects for the years 2004-2006. The inclusion of these projected plant additions has
17		the effect of significantly increasing the Company's proposed depreciation rates for
18		FERC plant account 312, the FERC plant account with the largest proposed increase in
19		depreciation rate.
20		

1 Q	<u>)</u> .	Should the Commission reflect future plant additions in depreciation rates?
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2

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A. No. These plant additions represent post test year adjustments and should not be reflected in the depreciation rates and depreciation expense included in the historic test year. These post test year adjustments violate the test year principle of consistency among all revenue requirement components. It is inequitable to selectively include projected post-test year cost increases without updating all revenue requirement components, including post-test year cost reductions and revenue increases that would reduce the revenue requirement.

10

11 The Commission previously has addressed this very issue of post test year additions and 12 their inclusion in rate base and depreciation expense. In Case No. 90-158, the Commission rejected LG&E's request to include post test year Trimble County plant 13 additions in the revenue requirement. It stated in that Order that "The Commission 14 cannot and will not include in rate base the post test-period plant additions for Trimble 15 County or the related first year depreciation expense. To do otherwise would disregard 16 established, and we feel fair, just and reasonable rate-making practices enunciated and 17 adopted in prior Commission decisions concerning post test-period plant additions." 18

19

1		In addition, the costs to reduce NOx emissions are recoverable by the Company through
2		the ECR surcharge mechanism. Some or all of these projected NOx compliance costs
3		already have been approved by the Commission in conjunction with the Company's
4		ECR compliance plans and are eligible for recovery through the ECR. Thus the
5		Company already has an established cost recovery mechanism in place to recover such
6		costs on a timely basis once they are incurred and are known and measurable. If and
7		when the Company actually incurs these projected NOx compliance costs, and if it is
8		unable recover them through the ECR, then it may seek to recover them through base
9		rates in a future base rate proceeding.
10		
11		Finally, if the Commission allows depreciation rates to be increased for post test year
12		projected capital additions for NOx compliance, then there no longer will exist any test
13		year boundary requiring the exclusion of any post test year capital additions.
14		Unfortunately, such a precedent could be relied upon by the Company or other
15		Companies in the future to justify other selective post test year adjustments that will
16		increase their revenue requirements.
17		
18	Q.	Have you quantified the effects on the depreciation rates and the resulting
19		depreciation expense of removing the future plant additions projected for NOx

20 compliance from FERC plant account 312?

1

2	A.	Yes. I have quantified the effects of removing the future plant additions projected for
3		NOx compliance from FERC plant account 312 as an additional adjustment to the
4		depreciation rates by FERC production plant location and depreciation expense
5		previously computed with the removal of the Company's adjustments to historic gross
6		salvage and cost of removal rates. The quantification is summarized on my
7		Exhibit(LK-6). In the final step, I utilized the rates that I previously computed in
8		"present rates" column lieu of the Company's present rates in order to quantify the
9		incremental effects of this recommendation compared to my preceding recommendation.
10		
11	<u>Retu</u>	<u>n on Common Equity</u>
12		
13	Q.	Have you quantified the effect on the Company's revenue requirement of KIUC
13 14	Q.	Have you quantified the effect on the Company's revenue requirement of KIUC witness Mr. Baudino's recommendation for the required return on common
	Q.	
14	Q.	witness Mr. Baudino's recommendation for the required return on common
14 15	Q. A.	witness Mr. Baudino's recommendation for the required return on common
14 15 16	-	witness Mr. Baudino's recommendation for the required return on common equity?
14 15 16 17	-	witness Mr. Baudino's recommendation for the required return on common equity? Yes. I utilized the Company's cost of capital obtained from Rives Exhibit 2 and simply
14 15 16 17 18	-	witness Mr. Baudino's recommendation for the required return on common equity? Yes. I utilized the Company's cost of capital obtained from Rives Exhibit 2 and simply replaced the Company's requested return on common equity with Mr. Baudino's

1	KIUC's recommended return on common equity translates to a grossed-up return
2	recoverable from ratepayers of 14.69%. The quantification of the revenue requirement
3	effect is detailed on my Exhibit (LK-7).

1 2		III. TERMINATION OF THE EARNINGS SHARING MECHANISM
3	The	ESM should be Terminated; It is Not a Supplemental Form of Regulation
4		
5	Q.	Should the Commission discontinue the ESM?
6		
7	A.	Yes. Although the ESM represented a reasonable alternative to the traditional form of
8		regulation during the trial period, it no longer is reasonable or an alternative. To the
9		contrary, the ESM likely will harm ratepayers through two simultaneous forms of
10		regulation, resulting in the combination of traditional base rate increases and annual
11		ESM rate increases. There no longer is any need to utilize the ESM as a means to
12		transition to potential deregulation. It is highly unlikely that Kentucky will deregulate in
13		the foreseeable future. In addition, the ESM has not served to reduce costs or improve
14		the quality of service. In any event, particularly in a period of increasing costs,
15		traditional regulation provides a greater incentive to reduce costs than does ESM
16		regulation because the Company retains the entire benefit of any such cost reductions
17		between traditional base rate increases.
18		
19	Q.	How have circumstances changed since the Commission offered the Company the
20		ESM as an alternative form of regulation in lieu of traditional regulation?
21		

۲

1	A.	First, the Company filed for substantial base rate increases in December 2003 pursuant
2		to traditional ratemaking, thus belying the notion that the ESM is an alternative form of
3		regulation. The net import of the Company's decision to file for a traditional base rate
4		increase is that any increase from such a filing will be effective mid-year 2004, which
5		will follow in short order the anticipated 2003 ESM increases that will be effective in
6		April 2004, and which will again be compounded by the anticipated 2004 ESM
7		increases that will be effective in April 2005 and continue through March 2006.
8		
9		Second, the Company now projects increasing costs, at least through 2006, according to
10		financial projections developed by the Company and shared with BWG during the
11		conduct of the management audit. Also, the Company plans to add additional
12		generating capacity in the next two years, according to recent press releases announcing
13		its intent to file for a traditional base rate increase in December 2003. These increases in
14		costs have the potential to result in additional traditional base rate increases
15		compounded by a continuing series of annual rate increases pursuant to the ESM.
16		
17		Third, deregulation of generation in Kentucky and nationwide no longer appears
18		inevitable or even likely. The ESM was conceived, according to statements by the
19		Commission in its Case Nos. 98-426 Order, as an interim step toward the potential
20		deregulation of generation and the related market pricing for such generation.

1		
2		Fourth, the Company acknowledges that the ESM has not operated to reduce costs or
3		improve the quality of service. The Company attributes any reductions in costs or
4		improvements in the quality of service that have been achieved to its own independent
5		initiatives undertaken for the benefit of their shareholder.
6		
7	Q.	Does the Company view the ESM as an <i>alternative</i> form of regulation or as a
8		supplemental form of regulation?
9		
10	А.	The Company clearly views the ESM as a supplemental form of regulation that can exist
11		simultaneously with the traditional cost of service form of regulation. As evidenced by
12		its request for a substantial base rate increase in this proceeding, the Company does not
13		consider the ESM to be a mutually exclusive form of regulation precluding the filing of
14		traditional base rate cases. In Case No. 2003-00334, Company witness Mr. Beer states
15		unequivocally that "LG&E and KU have a fundamental statutory right to seek a base
16		rate increase regardless of whether they are operating under an ESM The statutory
17		grants of authority to the Commission from the General Assembly do not provide the
18		Commission the power to alter or amend these rights." (Beer Direct, 4-5).
19		If the Company legally is correct in its position that the ESM and traditional ratemaking
20		are not mutually exclusive, then the ESM necessarily will operate to supplement the

1		traditional ratemaking process. The ESM provides for annual rate changes, which likely
2		will be increases based on the Company's projection of increasing costs, on an interim
3		basis until traditional base rate increases are implemented. Thus, the ESM will operate
4		as a supplemental form of regulation, not an alternative form of regulation.
5		
6	Q.	Has the ESM operated as an effective incentive to increase the Company's
7		managerial efficiency or to reduce its costs compared to traditional regulation?
8		
9	A.	No. Neither the Company nor the Commission's auditor, Barrington-Wellesley Group
10		("BWG") have identified a single initiative, cost reduction, or quality of service
11		improvement that was the result of the ESM. To the contrary, the Company's initiatives
12		to achieve efficiency and customer service have been independent of the existence of the
13		ESM. In its Final Report Section V-5, BWG claimed that the ESM had increased
14		managerial incentives. However, in Case No. 2003-00334, Company witness Mr. Beer
15		disputed that conclusion, stating that "This particular finding has no application to
16		companies like LG&E and KU. LG&E and KU will continue in the future, as they have
17		in the past, to operate through innovation and achieve efficiencies with high quality
18		customer service. Thus, while the ESM has not created a new corporate mindset for
19		LG&E and KU, it has served to re-enforce corporate initiatives to achieve efficiency and
20		customer service." (Beer Direct, 6-7).

Lane Kollen Page 37

1		
2	Q.	Does the Company project for the years 2003-2006 that it will earn less than the
3		10.5% lower threshold of the ESM earning deadband?
4		
5	A.	Yes. The BWG audit report stated that "Current projections indicate that the Companies
6		will remain in an under-earning position for the next several years." (Final Report, I-
7		10). For this conclusion, BWG relied upon the Companies' forecasts for the years 2003-
8		2006 and confirmed these projections in interviews with Mr. Rives and Ms. Scott. The
9		Company also confirmed its projections of underearnings in response to KIUC 1-10 in
10		that proceeding.
11		
12	Q.	What is the significance of the Company's projections that it will underearn the
13		lower threshold of the ESM earnings deadband at least through 2006 absent a
14		traditional rate increase?
15		
16	A.	The Company may file traditional rate increase requests in addition to the request in this
17		proceeding. In addition to these traditional base rate increases, the Company may obtain
18		additional annual rate increases through the ESM, to the extent it is continued.
19	Q.	Does the ESM provide greater incentives to the Company to reduce costs than
20		traditional ratemaking?

1

2	A.	No. To the extent ratemaking provides any incentives to the Company to reduce costs,
3		then traditional ratemaking provides greater incentives than the ESM simply due to the
4		ability of the Company to retain the entirety of the savings benefits and for longer
5		periods of time. I generally agree with BWG that "COSR provides incentives for the
6		regulated utility to control costs and optimize the utilization of rate base, some of the
7		benefits of such efficiencies eventually flow to the utility's customers. COSR provides
8		short-term immediate incentives to the utility to control costs between rate cases, but a
9		large share of the benefits of efficiency improvements flow to the customers in the
10		longer term." (BWG Report, I-9).
11		
12	Q.	How should the Commission discontinue the ESM?
13		
14	A.	The Commission should discontinue the ESM surcharge related to the ESM 2003 test
15		year effective on the same date as any increase from this proceeding becomes effective.
16		
17	Q.	Why should the Commission discontinue the ESM surcharge related to the ESM
18		2003 test year effective on the same date as any increase from this proceeding
19		becomes effective?
20		

1 The ESM rate increase and the traditional base rate increase from this proceeding are A. mutually exclusive pursuant to alternative forms of regulation. Both represent 2 prospective rate increases. The test years for the ESM and the traditional rate increase 3 overlap for nine months, thus effectively providing double recovery of the revenue 4 deficiencies associated with essentially the same revenue requirement. As such, the 5 6 traditional rate increase from this proceeding will be piled on to the rate increase from the ESM if the ESM surcharge is not terminated on the same date as the traditional rate 7 8 increase is effective. Doubling up on rate increases for essentially the same test period 9 necessarily results in excessive rates that cannot be just and reasonable. 10 11 The Commission allowed the Company to continue the ESM beyond the initial **O**.

11Q.The Commission anowed the Company to continue the ESM beyond the initial12three year period subject to prospective change in Case No. 2002-00472 and13retained BWG to conduct a management audit to determine whether the ESM14should be continued. BWG issued its Final Report on August 31, 2003,15recommending the continuation of the ESM. The Commission initiated "new16investigations" of the ESM in its Order in Case No. 2003-00334 dated September 4,172003. When did the Company decide to develop a traditional base rate filing?

18

1	Α.	The Company made this decision in June 2003 or before. The Company's consultants
2		and counsel retained to support its efforts in this proceeding commenced billing on the
3		project in June 2003, according to the Company's response to PSC 1-57.
4		
5	Q.	What is the significance of the fact that the Company already was preparing a base
6		rate increase filing at the very time the Commission's auditor was conducting the
7		management audit to determine whether the ESM should be continued.
8		
9	А.	This information was a material fact and directly relevant to the very issue being
10		investigated by the Commission. This fact should have been disclosed to the
11		Commission's auditors during the conduct of the management audit so that it could be
12		reported to the Commission, Staff, and other parties with an interest in the Company's
13		rates. Such information could have been considered by the Commission prior to its
14		decision on September 4, 2003 to continue the ESM. It may have resulted in a
15		completely different decision. Such information would have allowed KIUC and other
16		parties to oppose the continuance of the ESM and seek an expedited hearing in order to
17		terminate the ESM prior to the end of 2003.
18		The Commission should consider the failure of the Company to disclose this critical
19		information to the Commission's auditors on the timing of the termination of the ESM
20		surcharge. The Company's failure to disclose this critical and directly relevant

1		information prior to the Commission's September 4, 2003 Order is an additional reason
2		why the Commission should terminate the surcharge on the effective date of the rate
3		change in this proceeding.
4		
5	Q.	The Company apparently considers the ESM to be a true-up mechanism for the
6		historic period. Do you agree?
7		
8	A.	No. The Commission offered the Company the ESM as an alternative to traditional
9		regulation. The structure of the ESM provides for annual rate changes prospectively on
10		April 1 of the year following the calendar year test year based on that historic test year.
11		The structure of the ESM follows that of traditional ratemaking with the use of a historic
12		test year to set rates prospectively. The ESM simply established an annual and
13		expedited ratemaking process for prospective rate changes, along with a sharing of
14		revenue surpluses and deficiencies outside the earnings deadband.
15		
16		The ESM did not disturb the fundamental ratemaking principle that base rates may be
17		changed only prospectively. The Company's argument that the ESM operates as a true-
18		up mechanism necessarily rests upon the assumption that the Commission can change a
19		lawful rate retroactively. To the contrary, KRS §278.270 states that "Whenever the
20		Commission, upon its own motion or upon complaint as provided in KRS 278.260, and

1		after a hearing had upon reasonable notice, finds that any rate is unjust, unreasonable,
2		insufficient, unjustly discriminatory or otherwise in violation of any of the provisions of
3		this chapter, the commission shall by order prescribe a just and reasonable rate to be
4		followed in the future."
5		
6		Just and reasonable rates to be followed in the future may be set under either of the two
7		different methodologies, but just and reasonable rates to be followed in the future cannot
8		be established under two different methodologies based upon a largely overlapping test
9		year and then implemented simultaneously as sought by the Company.
10		
11	Q.	How does the Company's request to implement simultaneous prospective rate
12		increases under two alternative forms of regulation compare to the Commission's
13		initial implementation of the ESM in conjunction with a base rate reduction under
		initial implementation of the ESM in conjunction with a base rate reduction under
14		traditional ratemaking?
14 15		
	A.	
15	A.	traditional ratemaking?
15 16	A.	traditional ratemaking? When the ESM initially was implemented, the Commission was careful to avoid the
15 16 17	A.	traditional ratemaking? When the ESM initially was implemented, the Commission was careful to avoid the simultaneous operation of the two alternative forms of regulation and such doubling up.

1		request in this proceeding utilizes essentially the same test year to determine its revenue
2		deficiencies under both the ESM and traditional forms of ratemaking with the
3		simultaneous prospective implementation of the rate increases.
4		
5	Q.	Is there additional evidence that the Commission considered the ESM to set rates
6		prospectively rather than operate as a true-up mechanism for a historic period?
7		
8	A.	Yes. The Commission offered the Company the ESM in its Order in Case No. 98-426,
9		which the Company accepted in lieu of traditional regulation. The Commission also
10		reduced the Company's base rates in accordance with traditional regulation effective
11		March 1, 2000. Nevertheless, the Commission required the Company to annualize that
12		rate reduction for the ESM test year 2000. Thus, when rates were reset prospectively on
13		April 1, 2001, the rates did not double up the effects of the March 1, 2000 reduction.
14		Consequently, rates were reduced less on April 1, 2001 pursuant to the new form of
15		regulation than if the ESM had operated as a true-up mechanism.
16		
17		The Company supported this treatment when the ESM was implemented and KIUC
18		agreed with this treatment because the ESM reset base rates prospectively. The
19		Commission should reject the Company's argument now to consider the ESM a true-up

mechanism, an argument that is in direct contradiction to the position it took when the
 ESM was implemented.

1	<u>Tran</u>	sitioning the ESM if It is Not Discontinued
2		
3	Q.	How should the Commission reflect the mid-year 2004 traditional base rate
4		increases, if any, in the ESM 2004 test year if it is not discontinued?
5		
6	A.	The Commission should annualize the mid-year 2004 rate increases as if they were in
7		effect the entire year.
8		
9	Q.	Why should the Commission annualize the mid-year 2004 traditional base rate
10		increases, if any, in the ESM?
11		
12	A.	Such an approach is consistent procedurally and methodologically with the
13		Commission's annualization of the March 1, 2000 rate reductions in the initial 2000
14		ESM test year. In Case No. 98-426, the Company specifically sought rehearing on this
15		issue, proposing that the rate reductions be annualized to January 1, 2000 as if they had
16		been in effect the entire year. No party contested the Companies' request. The
17		Commission stated in its Orders on rehearing the following:
18		
19		The impacts of the Orders issued in this proceeding should be reflected in
20 21		the normalization of LG&E's [KU's] revenues for purposes of the initial
21 22		ESM review. That initial review will cover LG&E's [KU's] operations for calendar year 2000. Since the Orders in this case were issued during this
		the start year 2000. Since the orders in this case were issued untiling this

1 2 3		calendar year, the Commission finds it reasonable to reflect a full 12 months of the impact of these Orders in the initial ESM review.
4		Similarly, the Commission should annualize any rate increases to January 1, 2004 as if
5		they had been in effect the entire year. The precedent has been established, and at the
6		Company's request. There is no valid reason to depart from this precedent simply
7		because the change in base rates is an increase rather than a decrease.
8		
9		The failure to annualize any rate increases to January 1, 2004 would be inequitable and
10		penalize ratepayers in addition to the excessive and doubled up rates resulting from the
11		ESM 2003 test year coupled with any traditional rate increase in this proceeding. The
12		annualization of the rate reductions in the initial ESM test year decreased the earnings
13		available for sharing with ratepayers. To be symmetrical, just, and reasonable, the
14		Commission should ensure that the rate increases in the ESM 2004 test year increase the
15		earnings available (or reduce the amounts recoverable) for sharing with ratepayers.
16		
17	<u>The l</u>	ESM should be Modified If It is Continued
18		
19	Q.	If the ESM is continued, should the Commission consider it as an alternative form
20		of regulation, as originally intended, or allow it to be utilized in addition to

traditional regulation as a supplemental form of regulation between base rate cases?

3

2

1

A. The Commission should decide which form of regulation is appropriate for the
Company. If the Commission decides to offer the Company another three years of ESM
regulation, then it should include a condition whereby the Company would agree to
refrain from filing another traditional base rate increase with an effective date during the
term of the ESM regulation and surcharge period. If the Company is unwilling to accept
that condition, then the ESM should be discontinued regardless of the other merits of
termination.

11

12 The Commission should not change the nature of the ESM to provide a supplemental 13 form of regulation in addition to traditional regulation. In Case Nos. 98-426, the 14 Commission offered the Company the ESM as an alternative to traditional regulation, 15 noting in its Orders that "[T]he Commission will now offer LG&E an alternative to 16 traditional regulation in the form of an optional ESM plan." The Commission further 17 noted that "[O]ur Order in Case No. 97-300 specified that LG&E could choose 18 traditional or alternative rate-making."

19

1	Q.	Should the Commission annualize any mid-year 2004 traditional base rate
2		increases, if it continues the ESM?
3		
4	А.	Yes. Although I discussed this issue previously in conjunction with discontinuing the
5		ESM, the same rationale for such annualization applies if the ESM is continued. The
6		Commission already has established the precedent for such revenue annualizations and
7		at the request of the Company. Thus, there is no valid rationale to argue against such
8		annualizations, regardless of whether the ESM is continued or terminated.
9		
10	Q.	Should the Commission revise the return on equity utilized as the midpoint for the
11		earnings deadband if it continues the ESM?
12		
13	A.	Yes. The Commission should revise the midpoint return on equity to the return
14		authorized in this proceeding for the traditional base rate increase. The Commission
15		should modify the terms of the ESM to reflect changed circumstances. The 11.5% ESM
16		return on equity midpoint was established more than three years ago and does not reflect
17		the current cost of common equity. The midpoint is used to set the upper and lower
18		thresholds of the earnings deadband. The Commission's determination of the proper
19		and current cost of common equity will directly impact the level of the ESM annual rate

1		increases given that the Company projects it will earn below the lower threshold of the
2		current deadband at least through 2006.
3		
4	Q.	Should the Commission require that the earned returns be computed using average
5		monthly capitalization rather than year-end capitalization?
6		
7	A.	Yes. The Commission should explicitly require the use of average capitalization if the
8		ESM is continued. This was a contested issue in the Company's initial ESM filing and
9		was resolved through a Global Settlement in Case Nos. 2001-054 and 2001-055, but
10		only through 2002.
11		
12		The use of average capitalization provides a far superior measure of the earnings
13		achieved during the ESM test year than does year-end capitalization. Average
14		capitalization provides a better matching of all ratemaking components for the test year.
15		
16		

1 2 3		IV. BASE RATE REDUCTIONS UPON EXPIRATION OF MERGER SAVINGS AND VDT SURCREDITS
4		
5	Q.	Please describe the costs included in the Company's revenue requirement related
6		to the LG&E and KU merger.
7		
8	A.	In total, the Company has included \$37.938 million in the revenue requirement to reflect
9		the merger savings. The Company has included \$18.969 million in operating expense
10		for the shareholder's portion of the merger savings. In addition, the Company has
11		included the \$18.969 million ratepayer share of the merger savings in the base revenue
12		requirement. This latter amount is included by virtue of the Company using its total
13		operating revenues as the starting point for operating income, but then not removing the
14		effects of the merger surcredit in the same manner that it removes other surcharge
15		revenues and costs such as those for the ESM, DSM, and ECR.
16		
17	Q.	Please describe the costs included in the Company's revenue requirement related
18		to the 2001 employee buyout.
19		

1	A.	The Company has included \$17.290 million in the revenue requirement to reflect the
2		2001 employee buyout. I described these costs previously in conjunction with the
3		Company's failure to achieve labor cost savings.
4		
5	Q.	When are the merger surcredit and the VDT surcredit scheduled to terminate?
6		
7	А.	The merger surcredit is scheduled to terminate on June 30, 2008. The VDT surcredit is
8		scheduled to terminate on March 31, 2006.
9		
10	Q.	Why should the Commission be concerned about the scheduled termination dates
11		of the merger surcredit and VDT surcredit in this proceeding?
11 12		of the merger surcredit and VDT surcredit in this proceeding?
	A.	of the merger surcredit and VDT surcredit in this proceeding? The Company's base revenue requirement includes more than \$55 million of such costs.
12	A.	
12 13	A.	The Company's base revenue requirement includes more than \$55 million of such costs.
12 13 14	А.	The Company's base revenue requirement includes more than \$55 million of such costs. It is essential that when each of these surcredits terminate, and therefore the ratepayer
12 13 14 15	A.	The Company's base revenue requirement includes more than \$55 million of such costs. It is essential that when each of these surcredits terminate, and therefore the ratepayer sharing of the underlying savings terminates, that base rates be adjusted downward to
12 13 14 15 16	A.	The Company's base revenue requirement includes more than \$55 million of such costs. It is essential that when each of these surcredits terminate, and therefore the ratepayer sharing of the underlying savings terminates, that base rates be adjusted downward to remove all related costs included in the revenue requirement. Otherwise, ratepayers will
12 13 14 15 16 17	A.	The Company's base revenue requirement includes more than \$55 million of such costs. It is essential that when each of these surcredits terminate, and therefore the ratepayer sharing of the underlying savings terminates, that base rates be adjusted downward to remove all related costs included in the revenue requirement. Otherwise, ratepayers will be penalized, continuing to pay as if the surcredits remained in effect and as if there

1	Q.	What is your recommendation?
2		
3	A.	I recommend that the Company direct the Company in this proceeding to reduce its base
4		rates by the amounts included in its allowed revenue requirement related to each of the
5		surcredits upon their expiration, March 31, 2006 for the VDT surcredit and June 30,
6		2008 for the merger surcredit.

1 2		V. IMPLEMENTATION OF SYSTEM SALES CLAUSE
3	Q.	Please explain why the Commission should implement a System Sales Clause for
4		the Company.
5		
6	A.	First, a System Sales Clause is essential in order to capture on a consistent basis the
7		interrelated effects of the Company's variable fuel costs, purchased power costs, and
8		off-system sales revenues. Currently, the Company's Fuel Adjustment Clause ("FAC")
9		includes all recoverable fuel and purchased power costs, but only removes the fuel costs
10		associated with off-system sales, net of the amounts rolled into base rates. All off-
11		system sales margins above or below the amounts embedded into base rates in the last
12		base rate proceeding are retained by the Company. Unlike recoverable fuel and
13		purchased power costs, there currently is no rate mechanism to capture in whole or part
14		the variability in the off-system sales margins compared to the amounts embedded into
15		base rates.
16		
17		Second, the Company has included \$110 million in test year capitalization for the new
18		Trimble County CTs (7-10) that are scheduled to enter commercial service in April 2004
19		and June 2004. This amount represents nearly 80% of the estimated completion cost.
20		This additional capacity will provide the Company the opportunity to make additional
21		off-system sales compared to the test year. As a matter of equity, if the ratepayers are

1		required to pay for this capacity, then they should benefit at least in part from the
2		additional off-system sales margins that will be achieved due to this capacity.
3		
4	Q.	How should the Commission implement such a System Sales Clause?
5		
6	A.	I recommend that the Commission pattern a System Sales Clause after the Kentucky
7		Power Company ("KPC") Sales Clause. The KPC System Sales Clause provides for a
8		50% to Company and 50% to ratepayers sharing of the net change in off-system sales
9		margins compared to the amount embedded into base rates. I have attached a copy of
10		the KPC System Sales Clause tariff for reference purposes as my Exhibit(LK-8).
11		
12	Q.	Does this complete your testimony?
13		
14	А.	Yes.
15		

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

IN THE MATTER OF:

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

EXHIBITS

OF

LANE KOLLEN

ON BEHALF OF THE

KENTUCKY INDUSTRIAL UTILITY CUSTOMERS, INC.

J. KENNEDY AND ASSOCIATES, INC. ROSWELL, GEORGIA

MARCH 2004

RESUME OF LANE KOLLEN, VICE PRESIDENT

EDUCATION

University of Toledo, BBA Accounting

University of Toledo, MBA

PROFESSIONAL CERTIFICATIONS

Certified Public Accountant (CPA)

Certified Management Accountant (CMA)

PROFESSIONAL AFFILIATIONS

American Institute of Certified Public Accountants

Georgia Society of Certified Public Accountants

Institute of Management Accountants

More than twenty-five years of utility industry experience in the financial, rate, tax, and planning areas. Specialization in revenue requirements analyses, taxes, evaluation of rate and financial impacts of traditional and nontraditional ratemaking, utility mergers/acquisition diversification. Expertise in proprietary and nonproprietary software systems used by utilities for budgeting, rate case support and strategic and financial planning.

EXPERIENCE

1986 to

Present: J. Kennedy and Associates, Inc.: Vice President and Principal. Responsible for utility stranded cost analysis, revenue requirements analysis, cash flow projections and solvency, financial and cash effects of traditional and nontraditional ratemaking, and research, speaking and writing on the effects of tax law changes. Testimony before Connecticut, Florida, Georgia, Indiana, Louisiana, Kentucky, Maine, Minnesota, North Carolina, Ohio, Pennsylvania, Tennessee, Texas, and West Virginia state regulatory commissions and the Federal Energy Regulatory Commission.

1983 to

1986: Energy Management Associates: Lead Consultant.

Consulting in the areas of strategic and financial planning, traditional and nontraditional ratemaking, rate case support and testimony, diversification and generation expansion planning. Directed consulting and software development projects utilizing PROSCREEN II and ACUMEN proprietary software products. Utilized ACUMEN detailed corporate simulation system, PROSCREEN II strategic planning system and other custom developed software to support utility rate case filings including test year revenue requirements, rate base, operating income and pro-forma adjustments. Also utilized these software products for revenue simulation, budget preparation and cost-of-service analyses.

1976 to

1983: The Toledo Edison Company: Planning Supervisor.

Responsible for financial planning activities including generation expansion planning, capital and expense budgeting, evaluation of tax law changes, rate case strategy and support and computerized financial modeling using proprietary and nonproprietary software products. Directed the modeling and evaluation of planning alternatives including:

Rate phase-ins. Construction project cancellations and write-offs. Construction project delays. Capacity swaps. Financing alternatives. Competitive pricing for off-system sales. Sale/leasebacks.

CLIENTS SERVED

Industrial Companies and Groups

Air Products and Chemicals, Inc. Airco Industrial Gases Alcan Aluminum Armco Advanced Materials Co Armco Steel Bethlehem Steel Connecticut Industrial Energy Consumers ELCON Enron Gas Pipeline Company Florida Industrial Power Users Group General Electric Company GPU Industrial Intervenors Indiana Industrial Group Industrial Consumers for Fair Utility Rates - Indiana Industrial Energy Consumers - Ohio Kentucky Industrial Utility Customers, Inc. Kimberly-Clark Company

Lehigh Valley Power Committee Maryland Industrial Group Multiple Intervenors (New York) National Southwire North Carolina Industrial Energy Consumers Occidental Chemical Corporation Ohio Energy Group Ohio Industrial Energy Consumers Ohio Manufacturers Association Philadelphia Area Industrial Energy Users Group PSI Industrial Group Smith Cogeneration Taconite Intervenors (Minnesota) West Penn Power Industrial Intervenors West Virginia Energy Users Group Westvaco Corporation

Regulatory Commissions and Government Agencies

Georgia Public Service Commission Staff Kentucky Attorney General's Office, Division of Consumer Protection Louisiana Public Service Commission Staff Maine Office of Public Advocate New York State Energy Office Office of Public Utility Counsel (Texas)

Utilities

Allegheny Power System Atlantic City Electric Company Carolina Power & Light Company Cleveland Electric Illuminating Company Delmarva Power & Light Company Duquesne Light Company General Public Utilities Georgia Power Company Middle South Services Nevada Power Company Niagara Mohawk Power Corporation

Otter Tail Power Company Pacific Gas & Electric Company Public Service Electric & Gas Public Service of Oklahoma Rochester Gas and Electric Savannah Electric & Power Company Seminole Electric Cooperative Southern California Edison Talquin Electric Cooperative Tampa Electric Texas Utilities Toledo Edison Company

Date	Case	Jurisdict.	Party	Utility	Subject
10/86	U-17282 Interim	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Cash revenue requirements financial solvency.
11/86	U-17282 interim Rebuttal	LA	Louisiana Public Service Commission Staff	Guif States Utilities	Cash revenue requirements financial solvency.
12/86	9613	KY	Attomey General Div. of Consumer Protection	Big Rivers Electric Corp.	Revenue requirements accounting adjustments financial workout plan.
1/87	U-17282 Interim	LA 19th Judicial District Ct.	Louisiana Public Service Commission Staff	Gulf States Utilities	Cash revenue requirements, financial solvency.
3/87	General Order 236	WV	West Virginia Energy Users' Group	Monongahela Power Co.	Tax Reform Act of 1986.
4/87	U-17282 Prudence	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Prudence of River Bend 1, economic analyses, canceilation studies.
4/87	M-100 Sub 113	NC	North Carolina Industrial Energy Consumers	Duke Power Co.	Tax Reform Act of 1986.
5/87	86-524-E-	WV	West Virginia Energy Users' Group	Monongahela Power Co.	Revenue requirements. Tax Reform Act of 1986.
5/87	U-17282 Case In Chief	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Revenue requirements, River Bend 1 phase-in plan, financial solvency.
7/87	U-17282 Case In Chief Surrebuttal	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Revenue requirements River Bend 1 phase-in plan, financial solvency.
7/87	U-17282 Prudence Surrebuttal	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Prudence of River Bend 1, economic analyses, cancellation studies.

Date	Case	Jurisdict.	Party	Utility	Subject
7/87	86-524 E-SC Rebuttal	WV	West Virginia Energy Users' Group	Monongahela Power Co.	Revenue requirements, Tax Reform Act of 1986.
8/87	9885	KΥ	Attomey General Div. of Consumer Protection	Big Rivers Electric Corp.	Financial workout plan.
8/87	E-015/GR- 87-223	MN	Taconite Intervenors	Minnesota Power & Light Co.	Revenue requirements, O&M expense, Tax Reform Act
10/87	870220-EI	FL	Occidental Chemical Corp.	Florida Power Corp.	of 1986. Revenue requirements, O&M expense, Tax Reform Act of 1986.
1/87	87-07-01	СТ	Connecticut Industrial Energy Consumers	Connecticut Light & Power Co.	Tax Reform Act of 1986.
1/88	U-17282	LA 19th Judicial District Ct.	Louisiana Public Service Commission Staff	Gulf States Utilities	Revenue requirements, River Bend 1 phase-in plan, rate of return.
2/88	9934	KY	Kentucky Industrial Utility Customers	Louisville Gas & Electric Co.	Economics of Trimble County completion.
2/88	10064	KY	Kentucky Industrial Utility Customers	Louisville Gas & Electric Co.	Revenue requirements, O&M expense, capital structure, excess deferred income taxes.
5/88	10217	KY	Alcan Aluminum National Southwire	Big Rivers Electric	Financial workout plan. Corp.
5/88	M-87017 -1C001	PA	GPU Industrial Intervenors	Metropolitan Edison Co.	Nonutility generator deferred cost recovery.
/88	M-87017 -2C005	РА	GPU Industrial Intervenors	Pennsylvania Electric Co.	Nonutility generator deferred cost recovery.
5/88	U-17282	LA 19th Judicial District Ct.	Louisiana Public Service Commission Staff	Gulf States Utilities	Prudence of River Bend 1 economic analyses, cancellation studies, financial modeling.

Date	Case	Jurisdict.	Party	Utility	Subject
7/88	M-87017- -1C001 Rebuttai	PA	GPU Industrial Intervenors	Metropolitan Edison Co.	Nonutility generator deferred cost recovery, SFAS No. 92
7/88	M-87017- -2C005 Rebuttal	PA	GPU Industriai Intervenors	Pennsylvania Electric Co.	Nonutility generator deferred cost recovery, SFAS No. 92
9/88	88-05-25	ст	Connecticut Industrial Energy Consumers	Connecticut Light & Power Co.	Excess deferred taxes, O&M expenses.
9/88	10064 Rehearing	KY	Kentucky Industrial Utility Customers	Louisville Gas & Electric Co.	Premature retirements, interest expense.
10/88	88-170- EL-AIR	ОН	Ohio Industrial Energy Consumers	Cleveland Electric Illuminating Co.	Revenue requirements, phase-in, excess deferred taxes, O&M expenses, financial considerations, working capital.
10/88	88-171- EL-AIR	ОН	Ohio Industrial Energy Consumers	Toledo Edison Co.	Revenue requirements, phase-in, excess deferred taxes, O&M expenses, financial Considerations, working capital.
10/88	8800 355-EI	FL	Florida Industrial Power Users' Group	Florida Power & Light Co.	Tax Reform Act of 1986, tax expenses, O&M expenses, pension expense (SFAS No. 87).
10/88	3780-U	GA	Georgia Public Service Commission Staff	Atlanta Gas Light Co.	Pension expense (SFAS No. 87).
1/88	U-17282 Remand	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Rate base exclusion plan (SFAS No. 71)
2/88	U-17970	LA	Louisiana Public Service Commission Staff	AT&T Communications of South Central States	Pension expense (SFAS No. 87).
2/88	U-17949 Rebuttal	LA	Louisiana Public Service Commission Staff	South Central Bell	Compensated absences (SFAS No. 43), pension expense (SFAS No. 87), Part 32, income tax normalization,

Date	Case	Jurisdict.	Party	Utility	Subject
					
2/89	U-17282 Phase II	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Revenue requirements, phase-in of River Bend 1, recovery of canceled plant.
6/89	881602-EU 890326-EU	. –	Talquin Electric Cooperative	Talquin/City of Tallahassee	Economic analyses, incremental cost-of-service, average customer rates.
7/89	U-17970	LA	Louisiana Public Service Commission Staff	AT&T Communications of South Central States	Pension expense (SFAS No. 87), compensated absences (SFAS No. 43), Part 32.
8/89	8555	тх	Occidental Chemical Corp.	Houston Lighting & Power Co.	Cancellation cost recovery, tax expense, revenue requirements.
8/89	3840-U	GA	Georgia Public Service Commission Staff	Georgia Power Co.	Promotional practices, advertising, economic development.
9/89	U-17282 Phase II Detailed	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Revenue requirements, detailed investigation.
10/89	8880	ТХ	Enron Gas Pipeline	Texas-New Mexico Power Co.	Deferred accounting treatment, sale/leaseback.
0/89	8928	ТХ	Enron Gas Pipeline	Texas-New Mexico Power Co.	Revenue requirements, imputed capital structure, cash
0/89	R-891364	PA	Philadelphia Area Industrial Energy Users Group	Philadelphia Electric Co.	working capital. Revenue requirements.
1/89 2/89	R-891364 Surrebuttal (2 Filings)	PA	Philadelphia Area Industrial Energy Users Group	Philadelphia Electric Co.	Revenue requirements, sale/leaseback.
1/90	U-17282 Phase II Detailed Rebuttal	LA	Louisiana Public Service Commission Staff	Guif States Utilities	Revenue requirements detailed investigation.

Date	Case	Jurisdict.	Party	Utility	Subject
1/90	U-17282 Phase III	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Phase-in of River Bend 1, deregulated asset plan.
3/90	890319-Ei	FL	Florida Industrial Power Users Group	Florida Power & Light Co.	O&M expenses, Tax Reform Act of 1986.
4/90	890319-El Rebuttal	FL	Florida Industrial Power Users Group	Florida Power & Light Co.	O&M expenses, Tax Reform Act of 1986.
4/90	U-17282	LA 19th Judicial District Ct.	Louisiana Public Service Commission Staff	Gulf States Utilities	Fuel clause, gain on sale of utility assets.
9/90	90-158	KY	Kentucky Industriał Utility Customers	Louisville Gas & Electric Co.	Revenue requirements, post-test year additions, forecasted test year.
12/90	U-17282 Phase IV	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Revenue requirements.
3/91	29327, et. al.	NY	Multiple Intervenors	Niagara Mohawk Power Corp.	Incentive regulation.
5/91	9945	ТХ	Office of Public Utility Counsel of Texas	El Paso Electric Co.	Financial modeling, economic analyses, prudence of Palo Verde 3.
9/91	P-910511 P-910512	PA	Allegheny Ludlum Corp., Amico Advanced Materials Co., The West Penn Power Industrial Users' Group	West Penn Power Co.	Recovery of CAAA costs, least cost financing.
9/91	91-231 -E-NC	WV	West Virginia Energy Users Group	Monongahela Power Co.	Recovery of CAAA costs, least cost financing.
11/91	U-17282	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Asset impairment, deregulated asset plan, revenue require- ments.

Date	Case J	urisdict.	Party	Utility	Subject
12/91	91-410- EL-AIR	ОН	Air Products and Chemicals, Inc., Armco Steel Co., General Electric Co., Industrial Energy Consumers	Cincinnati Gas & Electric Co.	Revenue requirements, phase-in plan.
12/91	10200	тх	Office of Public Utility Counsel of Texas	Texas-New Mexico Power Co.	Financiał integrity, strategic planning, declined business affiliations.
5/92	910890-EI	FL	Occidental Chemical Corp.	Florida Power Corp.	Revenue requirements, O&M expense, pension expense, OPEB expense, fossil dismantling, nuclear decommissioning.
3/92	R-00922314	PA	GPU Industrial Intervenors	Metropolitan Edison Co.	Incentive regulation, performance rewards, purchased power risk, OPEB expense.
/92	92-043	KY	Kentucky Industrial Utility Consumers	Generic Proceeding	OPEB expense.
/92	920324-EI	FL	Florida Industrial Power Users' Group	Tampa Electric Co.	OPEB expense.
/92	39348	IN	Indiana Industrial Group	Generic Proceeding	OPEB expense.
/92	910840-PU	FL	Florida Industrial Power Users' Group	Generic Proceeding	OPEB expense.
/92	39314	IN	Industrial Consumers for Fair Utility Rates	Indiana Michigan Power Co.	OPEB expense.
1/92	U-19904	LA	Louisiana Public Service Commission Staff	Guif States Utilities/Entergy Corp.	Merger.
1/92	8649	MD	Westvaco Corp., Eastalco Aluminum Co.	Potomac Edison Co.	OPEB expense.
1/92	92-1715- AU-COI	ОН	Ohio Manufacturers Association	Generic Proceeding	OPEB expense.

Date	Case	Jurisdict.	Party	Utility	Subject
12/92	R-009223	78 PA	Armco Advanced Materials Co., The WPP Industrial Intervenors	West Penn Power Co.	Incentive regulation, performance rewards, purchased power risk, OPEB expense.
12/92 L	J-19949	LA	Louisiana Public Service Commission Staff	South Central Bell	Affiliate transactions, cost allocations, merger.
12/92	R-009224	79 PA	Philadelphia Area Industrial Energy Users' Group	Philadelphia Electric Co.	OPEB expense.
1/93	8487	MD	Maryland Industrial Group	Baltimore Gas & Electric Co., Bethlehem Steel Corp.	OPEB expense, deferred fuel, CWIP in rate base
1/93	39498	IN	PSI Industrial Group	PSI Energy, Inc.	Refunds due to over- collection of taxes on Marble Hill cancellation.
3/93	92-11-11	СТ	Connecticut Industrial Energy Consumers	Connecticut Light & Power Co.	OPEB expense.
3/93	U-19904 (Surrebutta	LA al)	Louisiana Public Service Commission Staff	Gulf States Utilities/Entergy	Merger. Corp.
3/93	93-01 EL-EFC	ОН	Ohio Industrial Energy Consumers	Ohio Power Co.	Affiliate transactions, fuel.
3/93	EC92- 21000 ER92-806-	FERC	Louisiana Public Service Commission Staff	Gulf States Utilities/Entergy	Merger. Corp.
1/93	92-1464- EL-AIR	он	Air Products Armco Steel Industrial Energy Consumers	Cincinnati Gas & Electric Co.	Revenue requirements, phase-in plan.
/93	EC92- 21000 ER92-806-4 (Rebuttal)	FERC	Louisiana Public Service Commission Staff	Gulf States Utilities/Entergy	Merger. Corp.

Date	Case	Jurisdict.	Party	Utility	Subject
9/93	93-113	KY	Kentucky Industrial Utility Customers	Kentucky Utilities	Fuel clause and coal contract refund.
9/93	92-490, 92-490A, 90-360-C	KY	Kentucky Industrial Utility Customers and Kentucky Attomey General	Big Rivers Electric Corp.	Disallowances and restitution for excessive fuel costs, illegal and improper payments, recovery of mine closure costs.
10/93	U-17735	LA	Louisiana Public Service Commission Staff	Cajun Electric Power Cooperative	Revenue requirements, debt restructuring agreement, River Bend cost recovery.
1/94	U-20647	LA	Louisiana Public Service Commission Staff	Gulf States Utilities Co.	Audit and investigation into fuel clause costs.
4/94	U-20647 (Surrebutta	LA I)	Louisiana Public Service Commission Staff	Gulf States Utilities	Nuclear and fossil unit performance, fuel costs, fuel clause principles and guidelines.
5/94	U-20178	LA	Louisiana Public Service Commission Staff	Louisiana Power & Light Co.	Planning and quantification issues of least cost integrated resource plan.
9/94	U-19904 Initial Post- Merger Ear Review	LA nings	Louisiana Public Service Commission Staff	Gulf States Utilities Co.	River Bend phase-in plan, deregulated asset plan, capital structure, other revenue requirement issues.
9/94	U-17735	LA	Louisiana Public Service Commission Staff	Cajun Electric Power Cooperative	G&T cooperative ratemaking policies, exclusion of River Bend, other revenue requirement issues.
10/94	3905-U	GA	Georgia Public Service Commission Staff	Southern Beil Telephone Co.	Incentive rate plan, earnings review.
10/94	5258-U	GA	Georgia Public Service Commission Staff	Southern Bell Telephone Co.	Alternative regulation, cost allocation.

Date	Case	Jurisdict.	Party	Utility	Subject
11/94	U-19904 Initial Post- Merger Ear Review (Rebuttal)		Louisiana Public Service Commission Staff	Gulf States Utilities Co.	River Bend phase-in plan, deregulated asset pian, capital structure, other revenue requirement issues.
11/94	U-17735 (Rebuttal)	LA	Louisiana Public Service Commission Staff	Cajun Electric Power Cooperative	G&T cooperative ratemaking policy, exclusion of River Bend, other revenue requirement issues.
4/95	R-0094327	1 PA	PP&L Industrial Customer Alliance	Pennsylvania Power & Light Co.	Revenue requirements. Fossil dismantling, nuclear decommissioning.
6/95	3905-U	GA	Georgia Public Service Commission	Southern Bell Telephone Co.	Incentive regulation, affiliate transactions, revenue requirements, rate refund.
6/95	U-19904 (Direct)	LA	Louisiana Public Service Commission	Gulf States Utilities Co.	Gas, coal, nuclear fuel costs, contract prudence, base/fuel realignment.
10/95	95-02614	TN	Tennessee Office of the Attorney General Consumer Advocate	BellSouth Telecommunications, Inc.	Affiliate transactions.
10/95	U-21485 (Direct)	LA	Louisiana Public Service Commission	Gulf States Utilities Co.	Nuclear O&M, River Bend phase-in plan, base/fuel realignment, NOL and AltMin asset deferred taxes, other revenue requirement issues.
11/95	U-19904 (Surrebuttal)	LA	Louisiana Public Service Commission	Gulf States Utilities Co. Division	Gas, coal, nuclear fuel costs, contract prudence, base/fuel realignment.
11/95 12/95	U-21485 (Supplement U-21485 (Surrebuttal)	LA al Direct)	Louisiana Public Service Commission	Gulf States Utilities Co.	Nuclear O&M, River Bend phase-in plan, base/fuel realignment, NOL and AltMin asset deferred taxes, other revenue requirement issues.

Date	Case J	urisdict.	Party	Utility	Subject
1/96	95-299- EL-AIR 95-300- EL-AIR	ОН	Industrial Energy Consumers	The Toledo Edison Co. The Cleveland Electric Illuminating Co.	Competition, asset writeoffs and revaluation, O&M expense, other revenue requirement issues.
2/96	PUC No. 14967	тх	Office of Public Utility Counsel	Central Power & Light	Nuclear decommissioning.
5/96	95-485-LCS	NM	City of Las Cruces	El Paso Electric Co.	Stranded cost recovery, municipalization.
7/96	8725	MD	The Maryland Industrial Group and Redland Genstar, Inc.	Baltimore Gas & Electric Co., Potomac Electric Power Co. and Constellation Energy Corp.	Merger savings, tracking mechanism, earnings sharing plan, revenue requirement issues.
9/96 1/96	U-22092 U-22092 (Surrebuttal)	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	River Bend phase-in plan, base/fuel realignment, NOL and AttMin asset deferred taxes, other revenue requirement issues, allocation of regulated/nonregulated costs.
0/96	96-327	KY	Kentucky Industriał Utility Customers, Inc.	Big Rivers Electric Corp.	Environmental surcharge recoverable costs.
!/97	R-00973877	PA	Philadelphia Area Industrial Energy Users Group	PECO Energy Co.	Stranded cost recovery, regulatory assets and liabilities, intangible transition charge, revenue requirements.
/97	96-489	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Power Co.	Environmental surcharge recoverable costs, system agreements, allowance inventory, jurisdictional allocation.
/97	TO-97-397	MO	MCI Telecommunications Corp., Inc., MCImetro Access Transmission Services, Inc.	Southwestern Bell Telephone Co.	Price cap regulation, revenue requirements, rate of return.

Date	Case	Jurisdict.	Party	Utility	Subject
6/97	R-009739	53 PA	Philadelphia Area Industrial Energy Users Group	PECO Energy Co.	Restructuring, deregulation, stranded costs, regulatory assets, liabilities, nuclear and fossil decommissioning.
7/97	R-009739	54 PA	PP&L Industrial Customer Alliance	Pennsylvania Power & Light Co.	Restructuring, deregulation, stranded costs, regulatory assets, liabilities, nuclear and fossil decommissioning.
7/97	U-22092	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Depreciation rates and methodologies, River Bend phase-in plan.
8/97	97-300	KY	Kentucky Industrial Utility Customers, Inc.	Louisville Gas & Electric Co. and Kentucky Utilities Co.	Merger policy, cost savings, surcredit sharing mechanism, revenue requirements, rate of return.
8/97	R-0097395 (Surrebutta		PP&L Industrial Customer Alliance	Pennsylvanía Power & Light Co.	Restructuring, deregulation, stranded costs, regulatory assets, liabilities, nuclear and fossil decommissioning.
10/97	97-204	KY	Alcan Aluminum Corp. Southwire Co.	Big Rivers Electric Corp.	Restructuring, revenue requirements, reasonableness
10/97	R-974008	ΡΑ	Metropolitan Edison Industrial Users Group	Metropolitan Edison Co.	Restructuring, deregulation, stranded costs, regulatory assets, liabilities, nuclear and fossil decommissioning, revenue requirements.
10/97	R-974009	PA	Penelec Industrial Customer Alliance	Pennsylvania Electric Co.	Restructuring, deregulation, stranded costs, regulatory assets, liabilities, nuclear and fossil decommissioning, revenue requirements.
11/97	97-204 (Rebuttal)	KY	Alcan Aluminum Corp. Southwire Co.	Big Rivers Electric Corp.	Restructuring, revenue requirements, reasonableness of rates, cost allocation.

Date	Case	Jurisdict.	Party	Utility	Subject
11/97	U-22491	LA	Louisiana Public Service Commission	Entergy Gulf States, Inc.	Allocation of regulated and nonregulated costs, other revenue requirement issues.
11/97	R-0097395 (Surrebutta	,,	Philadelphia Area Industrial Energy Users Group	PECO Energy Co.	Restructuring, deregulation, stranded costs, regulatory assets, liabilities, nuclear and fossil decommissioning.
11/97	R-973981	PA	West Penn Power Industrial Intervenors	West Penn Power Co.	Restructuring, deregulation, stranded costs, regulatory assets, liabilities, fossil decommissioning, revenue requirements, securitization,
11/97	R-974104	PA	Duquesne Industrial Intervenors	Duquesne Light Co.	Restructuring, deregulation, stranded costs, regulatory assets, liabilities, nuclear and fossil decommissioning, revenue requirements, securitization.
12/97	R-973981 (Surrebuttal)	PA	West Penn Power Industrial Intervenors	West Penn Power Co.	Restructuring, deregulation, stranded costs, regulatory assets, liabilities, fossil decommissioning, revenue requirements.
12/97	R-974104 (Surrebuttal)	PA	Duquesne Industrial Intervenors	Duquesne Light Co.	Restructuring, deregulation, stranded costs, regulatory assets, liabilities, nuclear and fossil decommissioning, revenue requirements, securitization.
1/98	U-22491 (Surrebuttal)	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Allocation of regulated and nonregulated costs, other revenue requirement issues.
2/98	8774	MD	Westvaco	Potomac Edison Co.	Merger of Duquesne, AE, customer safeguards, savings sharing.

Date	Case	Jurisdict.	Party	Utility	Subject
3/98	U-22092 (Allocated Stranded (LA Cost Issues)	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Restructuring, stranded costs, regulatory assets, securitization, regulatory mitigation.
3/98	8390-U	GA	Georgia Natural Gas Group, Georgia Textile Manufacturers Assoc.	Atlanta Gas Light Co.	Restructuring, unbundling, stranded costs, incentive regulation, revenue requirements.
3/98	U-22092 (Allocated Stranded C (Surrebutta		Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Restructuring, stranded costs, regulatory assets, securitization, regulatory mitigation.
10/98	97-596	ME	Maine Office of the Public Advocate	Bangor Hydro- Electric Co.	Restructuring, unbundling, stranded costs, T&D revenue requirements.
10/98	9355-U	GA	Georgia Public Service Commission Adversary Staff	Georgia Power Co.	Affiliate transactions.
10/98	U-17735	LA	Louisiana Public Service Commission Staff	Cajun Electric Power Cooperative	G&T cooperative ratemaking policy, other revenue requirement issues.
11/98	U-23327	LA	Louisiana Public Service Commission Staff	SWEPCO, CSW and AEP	Merger policy, savings sharing mechanism, affiliate transaction conditions.
12/98	U-23358 (Direct)	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Allocation of regulated and nonregulated costs, tax issues, and other revenue requirement issues.
12/98	98-577	ME	Maine Office of Public Advocate	Maine Public Service Co.	Restructuring, unbundling, stranded cost, T&D revenue requirements.
1/99	98-10-07	СТ	Connecticut Industrial Energy Consumers	United Illuminating Co.	Stranded costs, investment tax credits, accumulated deferred income taxes, excess deferred income taxes.

Date	Case	Jurisdict.	Party	Utility	Subject
3/99	U-23358 (Surrebutt	LA al)	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Allocation of regulated and nonregulated costs, tax issues, and other revenue requirement issues.
3/99	98-474	KY	Kentucky Industrial Utility Customers	Louisville Gas and Electric Co.	Revenue requirements, alternative forms of regulation.
3/99	98-426	KY	Kentucky Industrial Utility Customers	Kentucky Utilities Co.	Revenue requirements, alternative forms of regulation.
3/99	99-082	KY	Kentucky Industrial Utility Customers	Louisville Gas and Electric Co.	Revenue requirements.
3/99	99-083	KY	Kentucky Industrial Utility Customers	Kentucky Utilities Co.	Revenue requirements.
4/99	U-23358 (Suppleme Surrebutta		Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Allocation of regulated and nonregulated costs, tax issues, and other revenue requirement issues.
4/99	99-03-04	CT	Connecticut Industrial Energy Consumers mechanisms,	United Illuminating Co.	Regulatory assets and liabilities, stranded costs, recovery
4/99	99-02-05	СТ	Connecticut industrial Utility Customers mechanisms.	Connecticut Light and Power Co.	Regulatory assets and liabilities stranded costs, recovery
5/99	98-426 99-082 (Additional	KY Direct)	Kentucky Industrial Utility Customers	Louisville Gas and Electric Co.	Revenue requirements.
5/99	98-474 99-083 (Additional Direct)	KY	Kentucky Industrial Utility Customers	Kentucky Utilities Co.	Revenue requirements.
5/99	98-426 98-474 (Response Amended A	KY to Applications)	Kentucky Industrial Utility Customers Kentucky Utilities Co.	Louisville Gas and Electric Co. and	Alternative regulation.

Date	Case 、	lurisdict.	Party	Utility	Subject
6/99	97-596	ME	Maine Office of Public Advocate	Bangor Hydro- Electric Co.	Request for accounting order regarding electric industry restructuring costs.
6/99	U-23358	LA	Louisiana Public Public Service Comm. Staff	Entergy Gulf States, Inc.	Affiliate transactions, cost allocations.
7/9 9	99-03-35	СТ	Connecticut Industrial Energy Consumers	United Illuminating Co.	Stranded costs, regulatory assets, tax effects of asset divestiture.
7/99	U-23327	LA	Louisiana Public Service Commission Staff	Southwestern Electric Power Co., Central and South West Corp, and American Electric Power Co.	Merger Settlement Stipulation.
7/99	97-596 (Surrebuttal)	ME	Maine Office of Public Advocate	Bangor Hydro- Electric Co.	Restructuring, unbundling, stranded cost, T&D revenue requirements.
7/99	98-0452- E-GI	WVa	West Virginia Energy Users Group	Monongahela Power, Potomac Edison, Appalachian Power, Wheeling Power	Regulatory assets and liabilities.
8/99	98-577 (Surrebuttal)	ME	Maine Office of Public Advocate	Maine Public Service Co.	Restructuring, unbundling, stranded costs, T&D revenue requirements.
8/99	98-426 99-082 (Rebuttal)	KY	Kentucky Industrial Utility Customers	Kentucky Utilities Co.	Revenue requirements.
8/99	98-474 98-083 (Rebuttal)	ΚY	Kentucky Industrial Utility Customers Kentucky Utilities Co.	Louisville Gas and Electric Co. and	Alternative forms of regulation.
8/99	98-0452- E-GI (Rebuttal)	WVa	West Virginia Energy Users Group	Monongahela Power, Potomac Edison, Appalachian Power, Wheeling Power	Regulatory assets and liabilities.

Date	Case	Jurisdict.	Party	Utility	Subject
10/99	U-24182 (Direct)	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Allocation of regulated and nonregulated costs, affiliate transactions, tax issues, and other revenue requirement issues.
11/99	21527	тх	Dallas-Ft.Worth Hospital Council and Coalition of Independent Colleges and Universities	TXU Electric	Restructuring, stranded costs, taxes, securitization.
11/99	U-23358 Surrebutta Affiliate Transactio	LA al ons Review	Louisiana Public Service Commission Staff	Entergy Gutf States, Inc.	Service company affiliate transaction costs.
04/00	99-1212-6 99-1213-6 99-1214-6		Greater Cleveland Growth Association	First Energy (Cleveland Electric Illurninating, Toledo Edison)	Historical review, stranded costs, regulatory assets, liabilities.
01/00	U-24182 (Surrebutt	LA al)	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Allocation of regulated and nonregulated costs, affiliate transactions, tax issues, and other revenue requirement issues.
05/00	2000-107	KY	Kentucky Industrial Utility Customers	Kentucky Power Co.	ECR surcharge roll-in to base rates.
05/00	U-24182 (Suppleme	LA ental Direct)	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Affiliate expense proforma adjustments.
05/00	A-110550F	-0147 PA	Philadelphia Area Industrial Energy Users Group	PECO Energy	Merger between PECO and Unicom.
07/00	22344	тх	The Dailas-Fort Worth Hospital Council and The Coalition of Independent Coileges and Universities	Statewide Generic Proceeding	Escalation of O&M expenses for unbundled T&D revenue requirements in projected test year.
07/00	U-21453	LA	Louisiana Public Service Commission	SWEPCO	Stranded costs, regulatory assets and liabilities.

Date	Case	Jurisdict.	Party	Utility	Subject
08/00	U-24064	LA	Louisiana Public Service Commission Staff	CLECO	Affiliate transaction pricing ratemaking principles, subsidization of nonregulated affiliates, ratemaking adjustments.
10/00	PUC 223: SOAH 47	50 TX 3-00-1015	The Dallas-Ft. Worth Hospital Council and The Coalition of Independent Colleges And Universities	TXU Electric Co.	Restructuring, T&D revenue requirements, mitigation, regulatory assets and liabilities.
10/00	R-009741 (Affidavit)		Duquesne Industrial Intervenors	Duquesne Light Co.	Final accounting for stranded costs, including treatment of auction proceeds, taxes, capital costs, switchback costs, and excess pension funding.
11/00	P-000018 R-009740 P-000018 R-009740	08 38	Metropolitan Edison Industrial Users Group Penelec Industrial Customer Alliance	Metropolitan Edison Co. Pennsylvania Electric Co.	Final accounting for stranded costs, including treatment of auction proceeds, taxes, regulatory assets and liabilities, transaction costs.
12/00	U-21453, U-20925, (Subdocke (Surrebutt	et C)	Louisiana Public Service Commission Staff f	SWEPCO	Stranded costs, regulatory assets.
01/01	U-24993 (Direct)		Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Allocation of regulated and nonregulated costs, tax issues, and other revenue requirement issues.
01/01	U-21453, U and U-220 (Subdocke (Surrebutta	92 t B)	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc,.	Industry restructuring, business separation plan, organization structure, hold harmless conditions, financing.
01/01	Case No. 2000-386	KY	Kentucky Industrial Utility Customers, Inc.	Louisville Gas & Electric Co.	Recovery of environmental costs, surcharge mechanism.
01/01	Case No. 2000-439	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Utilities Co.	Recovery of environmental costs, surcharge mechanism.

Date	Case	Jurisdict.	Party	Utility	Subject
02/01	A-11030 A-110400	0F0095 PA F0040	Met-Ed Industrial Users Group Penelec Industrial Customer Alliance	GPU, Inc. FirstEnergy	Merger, savings, reliability.
03/01	P-000018 P-000018	-+	Met-Ed Industrial Users Group Penelec Industrial Customer Alliance	Metropolitan Edison Co. and Pennsylvania Electric Co.	Recovery of costs due to provider of last resort obligation.
04 /01	U-21453, U-20925, U-22092 (Subdocke Settlemen	LA et 8) t Term Sheet	Louisiana Public Public Service Comm. Staff	Entergy Gulf States, Inc.	Business separation plan: settlement agreement on overall plan structure.
04 /01	U-21453, U-20925, U-22092 (Subdocke Contested		Louisiana Public Public Service Comm. Staff	Entergy Gulf States, Inc.	Business separation plan: agreements, hold harmless conditions, separations methodology.
05 /01	U-21453, U-20925, U-22092 (Subdocke Contested Transmissi (Rebuttal)	1	Louisiana Public Public Service Comm. Staff	Entergy Gutf States, Inc.	Business separation plan: agreements, hold harmless conditions, Separations methodology.
07/01	U-21453, U-20925, U-22092 (Subdocke Transmissi	LA t B) on and Distribution	Louisiana Public Public Service Comm. Staff Term Sheet	Entergy Gulf States, Inc.	Business separation plan: settlement agreement on T&D issues, agreements necessary to implement T&D separations, hold harmless conditions, separations methodology.
10/01	14000-U	GA	Georgia Public Service Commission Adversary Staff	Georgia Power Co.	Review requirements, Rate Plan, fuel clause recovery.
11/01 (Direct)	14311-U	GA	Georgia Public Service Commission Adversary Staff	Atlanta Gas Light Co.	Revenue requirements, revenue forecast, O&M expense, depreciation, plant additions, cash working capital.

Date	Case	Jurisdict.	Party	Utility	Subject
11/01 (Direct)	U-25687	LA	Louisiana Public Service Commission	Entergy Gulf States, Inc.	Revenue requirements, capital structure, allocation of regulated and nonregulated costs River Bend uprate.
02/02	25230	ТХ	Dallas FtWorth Hospital Council & the Coalition of Independent Colleges & U		Stipulation. Regulatory assets, securitization financing.
02/02 (Surrebu	U-25687 ittal)	LA	Louisiana Public Service Commission	Entergy Gulf States, Inc.	Revenue requirements, corporate franchise tax, conversion to LLC, River Bend uprate.
03/02 (Rebuttal	14311-U i)	GA	Georgia Public Service Commission Adversary Staff	Atlanta Gas Light Co.	Revenue requirements, earnings sharing plan, service quality standards.
03/02	001148-Ei	FL	South Florida Hospital and Healthcare Assoc.	Florida Power & Light Co.	Revenue requirements. Nuclear Ilife extension, storm damage accruals and reserve, capital structure, O&M expense.
)4/02 Supplem	U-25687 nental Surrebu	LA ttal)	Louisiana Public Service Commission	Entergy Gulf States, Inc.	Revenue requirements, corporate franchise tax, conversion to LLC, River Bend uprate.
)4/02	U-21453, U- and U-2209; (Subdocket)	2	Louisiana Public Service Commission Staff	SWEPCO	Business separation plan, T&D Term Sheet, separations methodologies, hold harmless conditions.
8/02	EL01- 88-000	FERC	Louisiana Public Service Commission Statt	Entergy Services, Inc. and The Entergy Operating Companies	System Agreement, production cost equalization, tariffs.
8/02	U-25888	LA	Louisiana Public Service Commission	Entergy Gulf States, Inc. and Entergy Louisiana, Inc.	System Agreement, production cost disparities, prudence.
9/02	2002-00224 2002-00225	KY	Kentucky Industrial Utilities Customers, Inc.	Kentucky Utilities Co. Louisville Gas & Electric Co.	Line losses and fuel clause recovery associated with off-system sales.
1/02	2002-00146 2002-00147	KY	Kentucky Industrial Utilities Customers, Inc.	Kentucky Utilities Co. Louisville Gas & Electric Co.	Environmental compliance costs and surcharge recovery.
1/03	2002-00169	KY	Kentucky Industrial Utilities Customers, Inc.	Kentucky Power Co.	Environmental compliance costs and surcharge recovery.

Date	Case Ju	urisdict.	Party	Utility	Subject
04/03	U-26527	LA	Louisiana Public Service Commission	Entergy Gulf States, Inc.	Revenue requirements, corporate franchise tax, conversion to LLC, Capital structure, post test year Adjustments.
04/04	2002-00429 2002-00430	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Utilities Co. Louisville Gas & Electric Co.	Extension of merger surcredit, flaws in Companies' studies.
04/03	U-26527 I	LA	Louisiana Public Service Commission	Entergy Gulf States, Inc.	Revenue requirements, corporate franchise tax, conversion to LLC, Capital structure, post test year Adjustments.
06/03	EL01- 88-000 Rebuttai	FERC	Louisiana Public Service Commission Staff	Entergy Services, Inc. and the Entergy Operating Companies	System Agreement, production cost equalization, tariffs.
06/03	2003-00068	KU	Kentucky Industrial Utility Customers	Kentucky Utilities Co.	Environmental cost recovery, correction of base rate error.
11/03	ER03-753-000	FERC	Louisiana Public Service Commission Staff	Entergy Services, Inc. and the Entergy Operating Companies	Unit power purchases and sale cost-based tariff pursuant to System Agreement.
11/03	ER03-583-000, ER03-583-001, ER03-583-002 ER03-681-000,	, and	Louisiana Public Service Commission	Entergy Services, Inc., the Entergy Operating Companies, EWO Market- Ing, L.P, and Entergy Power, Inc.	Unit power purchase and sale agreements, contractual provisions, projected costs, levelized rates, and formula rates.
	ER03-681-001 ER03-682-000, ER03-682-001, ER03-682-002				
	ER03-744-000, ER03-744-001 (Consolidated				
04/03	U-26527 Surrebuttal	LA	Louisiana Public Service Commission	Entergy Guif States, Inc.	Revenue requirements, corporate franchise tax, conversion to LLC, Capital structure, post test year Adjustments

J. KENNEDY AND ASSOCIATES, INC.

Adjustments.

Date	Case Jurisdict.	Party	Utility	Subject
04/03	U-26527 LA Supplemental Surrebuttal	Louisiana Public Service Commission	Entergy Gulf States, Inc.	Revenue requirements, corporate franchise tax, conversion to LLC, Capital structure, post test year Adjustments.

EXHIBIT(LK-2)

			ŭ	Analysis For the Calenda	Case No Case No of Total Com	Kentucky Utilities Company Case No. 2003-00434 I Total Company Salaries al Vaste 1008 Historich 2003	Kentucky Utilities Company Case No. 2003-00434 Analysis of Total Company Salaries and Wages the Calender Verse 1008 through 2007 and the Total Version						
					000	"000 Omitted"							
					Caler	Idar Years P	Calendar Years Prior to Test Year	ear				Test	st
-		2	5th	4th	r	ъ.	3rd	2nd	P	1st	at l	Year	ar
		Amount	%	Amount	%	Amount	%	Amount	%	Amount	~	Amount	%
ġ		(q)	(c)	(p)	(e)	£	(a)	(4)	0	9	(K)	e	(m)
	Wages charged to expense						3						
~	Power Production Expense	24,957	-2.74%	24,905	-0.21%	30,705	23.29%	26.568	-13.47%	26.826	0 97%	27 120	1 1 30/
n,	I ransmission Expense	2,525	9.12%	2,910	15.25%		1 99%	3,155	10.62%		1 84%	3 735	0/ C1 .
4	Distribution Expense	13,231	5.66%	12,840	-2.96%	ſ	23.76%	10.658	32 03%		1 06%	14 504	10 C 10/0
5	Customer Accounts Expense	10,598	-6.38%	10.603	0.05%		-0.35%	6.810	35 46%		0/02.1-	14,031	02.04 %
9	Sales Expense	1,792	1.07%	1.850	3.24%		-15 95%	200	-100 00%	0.0	e/ nn. 1-	170'0	9/ 10:00
	Administrative and General						-	,	20000			?	
~	Expenses:												
	(a) Administrative and General												
	Salaries	10,070	-23.20%	7,889	-21.66%	13,002	64.81%	17.018	30.89%	20.530	20 64%	17 884	.17 89%
	(b) Office Supplies and Expenses							2	2000	200104	2		0/00/31-
	(c) administrative Exp. Transferred -												
	credit												
	(d) Outside services employed												
	(e) Property insurance								-			-	
	(f) Injuries and damages												
	(0) Employee pensions and henefits												
	(h) Franchise requirements										-		
	(I) Regulatory comminssion			+-									
	expense			_			•						
	() Duplicate charges - credit												
	(k) Miscellaneous general expense										, ,		
	(I) Maintenance of general plant					ļ				. _			
œ	Total Administrative and General Expenses L8(a) through L8(I)	10,070	-23.20%	7,889	-21.66%	13,002	64.81%	17.018	20.64%	20.530	20.64%	17 884	-12 89%
	Total Salaries and Wages charged												
6	expense (L2 through L7 + L8)	63,173	-39.67%	60,997	-27.95%	74,571	158.39%	64,218	-119.72%	67,201	30.82%	71,411	54.82%

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Attachment to PSC Question No. 23(c) Page 1 of 4 Scott

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			%	(m)	4.47%	5.91%			
	Test	Year	Amount	()	17,264	88.675		0.19	
				(K)	18.89%	7.18%			
		1st	Amount	9	16,526	83,727		0.20	
	i		%	€	18.89%	-10.18%			
st Year	ear	2nd	Amount	Ξ	13,900	78,118	0.82	0.18	
any s and Wages 2 and the Te	Calendar Years Prior to Test Year	P	%	(<u>6</u>)	-24.59%	12.31%			
Kentucky Utilities Company Case No. 2003-00434 f Total Company Salaries ar Years 1998 through 2002 a "000 Omitted"	dar Years Pr	3rd	Amount	() ()	12,399	86,970	0.86	0.14	
Kentucky Utilities Company Case No. 2003-00434 Analysis of Total Company Salaries and Wages the Calendar Years 1998 through 2002 and the Test Year "000 Omitted"	Calen		~ 3	(A)	0.36%	-2.66%			(c), (e), (g), (i), (k), and (m).
Analysis r the Calenda		4th	Amount	10	10,442	77,439	0.79	0.21	(c), (e), (g), (
For		_	%	1 700/	-4./0%	-44.42%			ar in Columns
		5th	Amount (b)	16 282	000'01	900,67	0.79	0.21	r the prior yea
		3	ltem (a)	Wages Capitalized	Total Salariae and Macan (4)	Patio of entration and uncert	charged to expense to total wages (L9/L11)	Ratio of salaries and wages capitalized to total wages (L10/L11)	Note: Show percent increae of each year over the prior year in Columns
			e No No	9	Т		12	13	Note: Si

Note: Salaries and wages above contain overhead amounts and represent total amount charged to KU. For example, Servco employees would charge KU for services performed for KU.

Total overtime dollars expended below represent all overtime charged to KU regardless of what company the employee works for.

	0,	•	ť	9	7itor to Test Year 6,645,313 -3.98%	hior to Test Year 6,920,702
Tool Var-		ist Calendar Year Prior to Test Year	Znd Calendar Year Prior to Test Year	3rd Calendar Year Prior to Test Year	4th Calendar Year Prior to Test Year	oth Calendar Year Prior to Test Year

(1) Does not include salaries and wages in balance sheet accounts other than Utility Plant and Removal

					Kentucky U	Kentucky Utilities Company	any						
			L.	Analysit For the Calenda	Case No s of Jurisdicti r Years 1996 r Years 1996	Case No. 2003-00434 Jurisdictional Salaries sars 1998 through 200 "000 Omitted"	Case No. 2003-00434 Analysis of Jurisdictional Salaries and Wages the Calendar Years 1998 through 2002 and the Test Year "000 Omitted"	st Year					
					Caler	rdar Years F	Calendar Years Prior to Test Year	(ear				ļ	Test
			5th	4th	-	Ē	3rd	21	2nd		1st	· >	Year
No.	ltem (a)	Amount	%	Amount	%	Amount	%	Amount	%	Amount	%	Amount	%
-	Wages charged to expense	Ð	<u>ច</u>	(p)	(e)	()	(6)	(Ļ)	0	()	(k)	9	Ē
8	Power Production Expense	21 139	70 Y L C	24 467	2								
m	Transmission Expense	1 080	0.120	201,12	0.11%		23.63%	22,614	-13.56%	22,822	0.92%	23,180	1.57%
4	Distribution Expense	12 120	3.12.70	11 046	10.05%			2,502	10.53%	2,443	-2.36%		5.21%
5	Customer Accounts Expense	0.887	280.0	040	-3.11%				-32.78%	9,773	-1.73%	13,680	39.97%
9	Sales Expense	1 682	1 07%	9'0'8	-0.00%			6,35	-35.46%	5,951	-6.34%	8,034	35.01%
	Administrative and General		2	00.1	0/.07.0	408	%CF.CI-	0	-100.00%	0		42	
~	Expenses:						·		_				
	(a) Administrative and General												
	Salaries	8,949	-23.20%	6.857	%18 86-	11 292	EA 68%	11 076	20 600			000 1,	1
	(b) Office Supplies and Expenses				2		e/ 00-10	010'+1	97.07.70	10,410	%J6.77	098, CL	-13.74%
	(c) administrative Exp. Transferred -												
	credit												
	(d) Outside services employed												
	(e) Property insurance												
	(f) Injuries and damages												
	(g) Employee pensions and henefits												
	(h) Franchise requirements												
	(I) Regulatory comminssion												
	expense		1					•					
	(i) Duplicate charges - credit												
	(k) Miscellaneous general expense			- <u> </u>									
	(I) Maintenance of general plant							+					T
8	Total Administrative and General Expenses L8(a) through L8(I)	8.949	-23.20%	6.857	7016 66-	11 202	64 60%	010 11	10E0 CC			4	
			2	555	2 20:04	70711	ov po. to	14,310	0/ 16.77	18,410	22.91%	988, CT	-13.74%
<u>б</u>	Total Salaries and Wages charged expense (L2 through L7 + L8)	55,965	-39,67%	53,878	-30.54%	65.817	159.04%	56.301	-115.67%	50 105	36 120	63 207	/02C 43
							hr 12:22	10000	N 0.0	COL'ED	e of no	720'00	04.71.40

Attachment to PSC Question No. 23(c) Page 3 of 4 Scott

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Note: Salaries and wages above contain overhead amounts and represent total amount charged to KU. For example, Servco employees would charge KU for services performed for KU.

Overtime dollars expended on a jurisdictional basis are not available.

(1) Does not include salaries and wages in balance sheet accounts other than Utility Plant and Removal

Kentucky Utilities Electric Division

Summary of Original Cost of Utility Plant in Service and Interim and Terminal Net Salvage

Account I No. (a)	311.00	312.00		315.00
Code (b)	5591 5604 5604 5604 5613 5615 5621 5622 5652 5651 5651 5651 5653 5653 5653		5651 C 5652 C 5652 C 5652 C 5654 C 5654 C 5661 C 56	17 A 10
Description (c) DEPRECIABLE PLANT	STEAM PLANT Structures and improvements KU Generation-Common Trone Unit 3 Trone Unit 3 Green River Unit 4 Green River Unit 4 Green River Unit 1 Brown Unit 1 Brown Unit 1 Brown Unit 3 Ghent Unit 2 Ghent Unit 2 Ghent Unit 3 Ghent Unit 4 Total Account 311	Boller Plant Equipment Trone Unit 3 Trone Units 1 & 2 Green River Unit 3 Green River Unit 4 Green River Unit 4 Brown Unit 2 Brown Unit 2 Brown Unit 2 Brown Unit 3 Greent 1 Pollution Control Equip.	Ghent Unit 1 Ghent Unit 2 Ghent Unit 2 Ghent Unit 3 Ghent Vit 4 Ghent 4 Rail Cars Todal Account 312 Turbue Unit 3 Trone Unit 3 Green River Unit 3 Green River Unit 1 Brown Unit 1 Brown Unit 1 Brown Unit 2 Ghent Unit 2 Ghent Unit 2 Ghent Unit 3 Ghent Unit 3 Ghent Unit 3 Ghent Unit 3 Ghent Unit 3 Ghent Unit 3	Total Account 314 Accessory Electric Equipment Trone Unit 3
Cost 12/31/02 (d)	805,715,82 5,293,882,85 5,293,882,85 5,993,882,85 2,599,390,94 3,797,160,20 4,099,390,94 3,749,160,20 4,052,142,19 1,452,821,256,37 12,4,352,142,19 16,012,556,37 40,539,13,20 21,953,259,20 21,953,259,20	8,663,220,42 3,549,368,50 9,061,059,76 18,776,499,07 12,249,873,99 32,815,581,55 26,010,201,59 71,536,455,78 71,536,455,78 86,308,756,05	88,266,090,96 86,733,989,30 168,701,912,41 7,647,232,19 790,197,504,49 2,649,841,16 1,592,029,04 2,562,629,04 2,562,629,04 2,562,620,04 8,323,622,300 4,645,56 8,323,622,300 4,645,56 8,323,622,300 4,645,56 8,323,622,300 4,569,15 22,985,210,48 8,729,916,37 8,729,916,37 8,729,916,37 8,729,916,37 8,729,916,37 8,729,916,37 8,729,916,37 8,729,916,37 8,729,916,37 8,729,916,37 8,729,916,37 8,729,916,37 8,729,916,37 8,729,916,37 8,729,916,37 8,729,916,37 8,729,916,37 8,711,389,85 22,385,520,55 36,111,389,85 22,385,55 22,385,500,55 36,111,389,85 22,385,500,55 36,111,332,55 22,385,55 23,385,55 23,55 24,55 25	191,722,845.06 570,736.22
Interim (e)	00000000000000000000000000000000000000	4 4 4 4 4 4 4 4 4 8 8 8 4 4 9 8 8 8 8 8	1444444 4	-6.3% 0.0%
Interim Net Salvage 24 Amount (f)	-3.223 -3.223 -2.356 -2.356 -15,16 -16,369 -16,363 -16,363 -16,363 -16,363 -6,364 -6,363 -5,140 -67,364 -67,364 -67,364 -67,364 -67,364 -67,165 -67,175 -67,17	415,835 415,835 -170,370 434,931 -901,272 -887,994 -1,575,148 -1,575,148 -3,433,750 -4,142,820 -4,142,820	4,142,020 4,143,125 8,097,692 -8,097,692 -367,067 -367,067 -367,068 -166,940 -166,940 -166,940 -166,940 -166,940 -166,940 -166,940 -166,940 -166,940 -166,940 -166,940 -174,053 -549,068 -1,449,068 -1,449,068 -1,786,577 -2401,018	-12,078,539 0
Terminal Net Salvage <u></u>	0.0% -7.7% -14.3% -15.1% -15.1% -15.2% -15.2% -15.2% -13.4% -13.4% -14.8%		-5.5% -5.5% -5.5% -5.5% -2.8% -2.8% -5.1,2% -5.1,2% -5.1,2% -5.1,2% -5.1,2% -5.1,2% -5.1,2% -5.1,2% -5.1,2% -5.1,2% -5.5% -5%	-3.8%
Lerminal Net Salvage <u>%</u> (9) (n)		-1,000,027 -710,384 -756,646 -710,260 -1,070,260 -1,070,260 -1,082,914 -1,682,914 -1,682,914 -1,682,916 -3,862,969 -4,832,2969	4,756,477 4,776,367 4,770,365 4,770,365 4,770,365 4,770,365 4,770,565 4,770,565 -33,256 -33,256 -33,029 -33,029 -33,029 -33,029 -33,029 -33,029 -33,029 -33,029 -33,029 -33,029 -33,029 -33,029 -33,029 -33,029 -33,029 -33,026 -34,026 -34,026 -34,026 -34,026 -34,026 -34,026 -34,026 -34,026 -33,026 -34,026 -33,026 -34,026 -33,00	-7,235,023
			-10.4% -10.2% -7.6% -7.6% -7.5% -10.2% -1.4.7% -14.7% -14.7% -14.5% -14.5% -14.5% -11.1% -11.1% -10.1% -10.1% -13.5% -11.1% -10.1% -13.5% -10.1% -13.5% -10.2% -10.2% -7.6% -7.16% -7.6% -7.6% -7.16% -7.6% -7.117% -7.117%	-10.1%
Total Net Salvage Manuat () ()	-3,223 -3,223 -428,805 -86,643 -418,805 -637,749 -637,749 -537,749 -3,360,566 -3,336,566 -3,336,565 -3,356 -3	-22,299,672 -1,126,219 -756,015 -1,141,592 -1,971,532 -1,298,487 -1,298,487 -2,558,062 -2,558,062 -7,296,718	-8,976,111 -8,973,45 -8,933,601 -12,893,281 -12,893,281 -12,893,281 -72,182,630 -389,527 -284,973 -838,557 -400,558 -633,804 -1,082,510 -2,516,666 -2,516,666 -2,516,666 -2,516,666 -3,468,136 -4,066,194	-19,313,562
ASL/Curve	90-51.5 90-51.5 90-51.5 90-51.5 90-51.5 90-51.5 90-51.5 90-51.5 90-51.5	70-L15 70-L15 70-L15 70-L15 70-L15 70-L15 70-L15 70-L15 70-L15 70-L15	70-115 70-115 70-115 70-115 70-115 70-115 70-115 60-S15 60	
Ave Age At Ret ()	8 8 8 8 8 8 8 8 8 8 8 8 8 8 8 8 8 8 8	**************************************	88.0 89.0 89.0 89.0 89.0 89.0 89.0 89.0 89.0 89.0 89.0 89.0 89.0 89.0 80.0	2
Iowa Curve Percent Surv (m)	92% 92% 92% 92% 92% 92% 92% 92% 92% 92%	8 8 8 1 8 1 8 1 8 1 8 1 8 1 8 1 8 1 8 1	81% 81% 81% 81% 81% 81% 75% 75% 75% 75% 75% 75%	2
Percent Retirement (n)	c c c c c c c c c c c c c c c c c c c	19% 19% 19% 19%	19% 19% 19% 19% 19% 25% 25% 25% 25% 25% 25%	%.c7
Interim Retired Amount (o)	64,457 64,457 423,511 47,155 327,951 327,051 327,051 116,226 966,299 1,948,171 1,266,291 1,266,261	1,646,012 674,380 1,721,601 3,565,535 2,327,476 6,234,960 6,234,960 13,591,938	16,398,664 16,770,937 16,770,937 32,053,363 1,452,974 1,452,974 1,452,974 662,460 662,460 3898,007 662,911 662,911 2,089,687 662,911 2,182,479 5,745,003 5,688,167 7,099,590	12,047,042
Interim Retired (p)	% % % % % % % % % % % % % % % % % % %		-25% -25% -25% -25% -25% -25% -25% -25%	- 728
Factored Amount (q)	-3,223 -2,1,176 -2,1,176 -2,3359 -1,1,2339 -1,1,2339 -1,1,2335 -5,811 -5,811 -5,811 -5,811 -5,811 -5,811 -64,050 -67,059 -67,059 -67,059 -67,059	411,503 -168,595 -403,400 -891,884 -581,869 -1,558,740 -1,235,485 -3,397,982	64,192,734 4,192,734 4,192,734 86,153,884 86,013,341 -8,013,341 -8,013,341 -8,013,341 -8,013,341 -8,013,341 -165,615 -99,502 -165,728 -520,226 -172,672 -172,578 -172,578 -1,477,042 -1,477,042 -1,477,338	(011,911
Interim Ret % Of Total Investment (r)	00000000000000000000000000000000000000	4 4 4 4 4 4 4 8 8 8 8 8 8 8 8 8 8 8 8 8		-6.3%

Table 2-a

Exhibit___(LK-3) Page 1 of 5 Kentucky Utilities Electric Division

Table 2-a

Summary of Original Cost of Utility Plant In Service and Interim and Terminal Net Salvage

			Original		u	etimotod Eut	the Piet Cart					nterim Reti	Interim Retirement Rate Calculation	Calculation			
Account	Account Location		Cost	Interim N	L	Terminal N	Terminal Net Salvado	ſ	Total Mat Cature	Interim,	en i	lowa Curve		Interim	Interim		Interim Ret.
(e)	90 3 9	Description	12/31/02	%	% Amount	%	Amount	N 1917	Amount	ASI /Curve	At Ret.	Percent Surar	Percent	Retired	Retired		% Of Total
	5613	Green River Llnit 3	(a) COC DCD 20	(e)	6)	(6)	£	ε	0	(K)	e				Kate	벽	Investment
	5614	-	697765'060 30 030 030	0.0% 0.0%	0	-9.3%	-64,761	-9.3%	-64,761	75-S2	43.8	89%	11%	76 500	/00 (A)	(j)	(I)
	5615	-	003,203,30 584,072 20	0.0% 0.0%	0 0	-12.1%	-97,922	-12.1%	-97,922	75-S2	43.8	89%	11%	89.020	%) %)		%0:0
	5621	_	2 663 640 MO	%0.0	> <	%Z'LL-	-65,416	-11.2%	-65,416	75-S2	43.8	%68	11%	64 248	%0 %0		%0.0
	5622	Brown Unit 2	970.596.10	%0.0		-3.7%	-98,555	-3.7%	-98,555	75-S2	43.8	89%	11%	293,000	* °	00	%00
	5623		5.076.639.52	200 700	-	-10.9% -	-104,325	-15.9%	-154,325	75-S2	43.8	89%	11%	106,766	%0		%000 700%
	5650		3 016 784 27	%0.0 0		-18.9%	-959,485	-18.9%	-959,485	75-S2	43.8	89%	11%	558.430	°,0		%000 %000
	5651		7 456 587 14	×0.0		-39.8%	-1,200,680	-39.8%	-1,200,680	75-S2	43.8	89%	11%	331 846	76V		
	5652	Ghent Unit 2	10 785 959 50	800		-10.1%	-1,200,511	-16.1%	-1,200,511	75-S2	43.8	89%	11%	820.225	%0	• •	%
	5653		25 D61 221 B4	% 0.00 0	2 0	-11.1%	-1,197,242	-11.1%	-1,197,242	75-S2	43.8	89%	11%	1.186.456	% 2		0.0% 20.0%
	5654	•	21.869.238.82	%0.0 0.0%	50	4.6%	-1,194,216	4.6%	-1, 194,216	75-S2	43.8	89%	11%	2.855.734	%0 0		%0°D
				Ø 0.0	Þ	%C.C-	-1,202,808	-5.5%	-1,202,808	75-S2	43.8	89%	11%	2,405,616	%0	> c	%0.0
		Total Account 315	81,289,114,47	%0.0	0	-9.3%	-7,553,406	-9.3%	-7,553,406						2	•	0.00
316.00		Miscellaneous Power Plant Equipment	•														
	5591	Svstem Laboratory	TO 100 000 1	200.0													
	5603	·		%0.0	5	0.0%	0	0.0%	0	60-S1	33.5	81%	19%	753 754	/80	Ċ	
	5604		41.040.044	0.0% 0.0%	0	-0.7%	-2,825	-0.7%	-2,825	60-S1	33.5	81%	10%	TC 1,202	8 0 0	ç	%0.0
	5613		40'700'14	0.0%	a	4.7%	-2,235	-4.7%	-2.235	60-S1	33.5	81%	200	1000	\$5	5	0.0%
	5614	Green River Unit 4	/ 0,833.53	0.0%	0	3.8%	-2,692	-3.8%	-2.692	60-S1	335	8 - 0 7 - 0	0/ n +	8,030 42,450	%0	0	0.0%
	5615		1,961,965.76	0.0%	0	-0.2%	-3,924	-0.2%	-3 924	60-S4	2000 2010	9 19	200	13,438	%0	¢	0.0%
	5621		190,224.48	0.0%	G	-1.4%	-2,663	-14%	-2 663	505	0.00	% I 0	19% 1	372,773	%0	0	0.0%
			293,859.48	0.0%	0	-1.4%	4114	1 4%	1111		0.00	01% 0	19%	36,143	%0	0	0.0%
	2022	Brown Unit 2	85,647.82	0.0%		-7.6%	902	2021	4 	12-00	33.5	81%	19%	55,833	%0	¢	0.0%
	5296	Brown Unit 3	3,695,436,94	0.0%		-1 7%	50 C2	9/ D' 1-	600'Q-	00-51 20 21	33.5	81%	19%	16,273	%0	0	0.0%
	5650	Ghent 1 Pollution Control Equip.	985,410.01	0.0%		8.0%	720,227	0/ J.I-	778'70-	60-S1	33.5	81%	19%	702,133	%0	0	0.0%
	5651	Gherrt Unit 1	1.683.635.89	%0 U	。 ⊂	20-7 7	20,000	-0.U%	-/8,833	60-S1	33.5	81%	19%	187,228	%0	c	76U U
	5652	Ghent Unit 2	1,478,017,69	%0.0		200	101,87-	%. •	-79,131	60-S1	33.5	81%	19%	319,891	%0		0.0%
	5653	Ghent Unit 3	3.135.971.64	%0.0 V 0.0) c	200-	10,000	-0.3%	-78,335	60-S1	33.5	81%	19%	280,823	%0	• =	0.0%
	5654	Ghent Unit 4	5,356,692.15	0.0%		-1.5% 15%	-70,359	-7.5%	-78,399	60-S1	33.5	81%	19%	595,835	%0	0	0.0%
						ev c: 1-	0000-	%C'L-	-80,350	60-S1	33.5	81%	19%	1.017.772	%0		200
		Total Account 316	20,719,081.14	%0.0	0	-2.3%	-482,833	-2.3%	-482,833							,	2
		Total Steam Production Plant	1,238,639,877.38	-4.1%	-50,615,977	-5.7%	-71,216,126	-9.8%	-121.832.103								
330.10		HYDRAULIC PLANT Land Richts															
	5691 5692	Dix Dam Lock #7	879,311.47 0.00	%0.0	00	0.0% 0.0%	00	%0.0	0	50-R2.5			100%	879,311	%0	0	%0'0
					0	8 A.A	0		0							•	
		f otal Account 330.10	879,311.47	0.0%	0	0.0%	0	0.0%	0								
331.00		Structures and improvements															
	5691 5692	Dix Dam Lock #7	429,524.71 67,902.49	-2.8% -2.8%	-12,027 -1,901	-12.2% -8.6%	-52,402 -5,840	-15.0% -11.4%	-64,429 -7,741	140-L1 140-L1	49.5 49.5	86% 86%	14%	60,133 0.500	-20%	-12,027	-2.8%
		Total Account 331	497,427.20	-2.8%	-13 Q2R	70/	010				2	2	R	onc's	%.07-	-1.901	-2.8%
						2		- 14.3%	0/1/2/-								

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Summary of Original Cost of Utility Plant in Service and Interim and Terminal Net Salvage

	Account			Original Cost	Interim N		<u>Stimated Futt</u>	Estimated Future Net Salvage			Interim		Interim Reti Iowa Curve	rement Rate	Interim Retirement Rate Calculation owa Curve	Interim		Interim Ret.
Image: constrained with the sector function of the sector function o	(e)	ව්ඩ	Desc	12/31/02 (d)	% (e)	Arrount (f)	(5)	Amount (h)		et Salvage Amount ()	Ret ASL/Curve (v)	At Ret. (Yrs)		Percent tetirement	Retired Amount	Retired Bate		% Of Total Investment
	332.00	5691 5692		7,818,030.36 324,145.88	0.0 %0.0	00	-0.1% -1.8%	-7,818 -5,835		-7,818 -5,835	150-L1.5 150-L1.5	53.0 53.0	%68 68	11%	859,983			(1) 0.0%
Number function Number of manage Number of manage </td <td></td> <td></td> <td>Total Account 332</td> <td>8,142,176.24</td> <td>%0</td> <td>0</td> <td>-0.2%</td> <td>-13,653</td> <td></td> <td>-13,653</td> <td></td> <td>0.00</td> <td>9/ RO</td> <td>%[]</td> <td>35,656</td> <td>%0</td> <td>0</td> <td>0.0%</td>			Total Account 332	8,142,176.24	%0	0	-0.2%	-13,653		-13,653		0.00	9/ RO	%[]	35,656	%0	0	0.0%
Toli Monount 33 S2,623.3 Op C2.34 (19,06) C2.34 (10,06) C2.34 (10,06) C2.34 (10,06) C2.34 (10,06) C2.34 (333.00	5691 5692		418,543.74 114,085.49	0.0% 0.0%	00	-25.8% -10.5%	-107,984 -11,979	-25.8% -10.5%	-107,984 -11,979	150-L1.5 150-L1.5	62.0	87% 87%	13%	54,411	%0	0	0.0%
Montower function Montower function 600 low if 24,4453 0.05 1<15			Total Account 333	532,629.23	%0.0	0	-22.5%	-119,963	-22.5%	-119,963			<u>%</u>	% <u>5</u>	14,831	%0	0	0.0%
Total Account 34 369.604 0.0 - <td>2</td> <td>5691 5692</td> <td></td> <td>85,383.13 264,485.91</td> <td>0.0% 0.0%</td> <td>00</td> <td>-29,4% -1.1%</td> <td>-25,103 -2,909</td> <td>-29.4% -1.1%</td> <td>-25,103 -2,909</td> <td>55-L1 55-L1</td> <td>23.6 23.6</td> <td>74% 74%</td> <td>26% 26%</td> <td>22,200</td> <td>%0</td> <td>0</td> <td>%0.0 %0</td>	2	5691 5692		85,383.13 264,485.91	0.0% 0.0%	00	-29,4% -1.1%	-25,103 -2,909	-29.4% -1.1%	-25,103 -2,909	55-L1 55-L1	23.6 23.6	74% 74%	26% 26%	22,200	%0	0	%0.0 %0
Image: Sector 1000 Image: Sector 10000 Image: Sector 100000 Image: Sector 100000 <th< td=""><td></td><td></td><td>Total Account 334</td><td>349,869.04</td><td>%0.0</td><td>0</td><td>-8.0%</td><td>-28,012</td><td>-8.0%</td><td>-28.012</td><td></td><td></td><td></td><td>8.07</td><td>00' V00</td><td>%0</td><td>D</td><td>0.0%</td></th<>			Total Account 334	349,869.04	%0.0	0	-8.0%	-28,012	-8.0%	-28.012				8.07	00' V00	%0	D	0.0%
Total Account 335 Total Account 336 Total Account 346	335.00	5691 5692		97,031.59 66,094.89	%0.0 %0.0	00	-3.5% -0.6%	-3,396 -397	-3.5% -0.6%	-3,396	55-R3 55-R3	23.3 23.3	%06 800	10%	9,703	% 0	0	%0.0
Fordet, Failtroade and Endique Fordet,			Total Account 335	163,126.48	%0.0	0	-2.3%	-3,793	-2.3%	-3.793	1	2	e 26	≪ ⊇	609'0	%0	0	0.0%
Total Account 36 48,145,91 0,0 0,0 0 0,0 0 0,0 0 0,0	0	5691 5692	-	46,976.12 1,169.79	0.0% 0.0%	00	%0.0 %0.0	00	0.0 %0.0	00	80-R5 80-R5	12.0	50% 50%	50% 50%	23,488	%0	0	%0.0
Total Hydraulic Plant 10,612,685,57 0% -13,928 2.1% -223,652 -2.2% -237,590 Chiefe PeroDuction HANT Land Rights 10,612,685,57 0% -13,928 2.1% -223,650 -237,590 Land Rights 178,409 176,409 176,409 176,409 -15% -26,461 Chiefe PeroDuction HANT 176,409 176,409 0 0.0% 0 0.0% 0 50% -237,590 Land Rights 176,409 176,409 176,409 166,409 -15% -26,461 - Call Account 340,10 176,409 176,409 0			Total Account 336	48,145.91	0.0%	Q	%0.0	0	0.0%	0		2.4	8.00	* <u>2</u>	ŝ	%D	0	0.0%
OTHER PEROLUCTION PLANT OTHER PEROLUCTION PLANT 5645 Bown 9 Pipeline 176,400.31 0% 0 0.0% 0 50-R2.5 100% 176,409 -15% -26.461 1 rein Propunt 176,400.31 0% 0 0.0% 0 0.0% 0 0.0% 0 -15% -26.461 -2			Total Hydraulic Plant	10,612,685.57	%0		-2.1%	-223,662	-2.2%	-237,590								
Total Account 340.10 T/6.400.31 0% 0 0.0% 0 0.0% 0 0.0% 1.5.461 -1.5.% -26.461 Structures and Improvements Structures and Improvements 3.9% -74.503 4.3% -82.144 8.2% -156.647 45.R05 18.8 7.4% 26% 496.685 -15% -74.503 0432 Padrivs Run GT 13 1.910.327.76 3.9% -139.003 -5.0% -166.931 6.9% -26.56.940 45.R05 18.8 7.4% 26% 496.685 -15% -74.503 0470 Timble Co 6 3.564.353.91 3.9% -106.931 6.9% -26.56.940 45.R05 18.8 7.4% 26% 496.685 -15% -24.503 5638 Brown 5 7.51.4865 -3.9% -108.680 -113.3% -85.32 45.R05 18.8 7.4% 26% 456 55% -24.615 55% -34.61 56% -35% -139.062 55% -34.61 -135.86 -139.86 <td< td=""><td>-</td><td>5645</td><td>OTHER PRODUCTION PLANT Land Rights Brown 9 Pipeline</td><td>176,409.31</td><td>%0</td><td>o</td><td>%0.0</td><td>Ð</td><td>%0.0</td><td>o</td><td>50-R2 5</td><td></td><td></td><td>10000</td><td>007 027</td><td></td><td></td><td></td></td<>	-	5645	OTHER PRODUCTION PLANT Land Rights Brown 9 Pipeline	176,409.31	%0	o	%0.0	Ð	%0.0	o	50-R2 5			10000	007 027			
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Brown F 133/17-33 -29/45 -74% -55/881 -11.3% -85,332 45-R0.5 18.8 74% 26% 196,339 15% -139/10 Brown 7 133/678.33 -39% -5.213 -11.3% -85,332 45-R0.5 18.8 74% 26% -93,339 15% -29,451 Brown 7 2.012.664.45 -3.9% -19,406 -71.7% -154,800 45-R0.5 18.8 74% 26% 34,756 -15% -19,406 Brown 9 2.012.664.45 -3.9% -191,007 -201,266 45-R0.5 18.8 74% 26% 136,457 -5,213 -19,406 Brown 10 1.865,718.20 -3.9% -733,457 -10.0% -201,266 45-R0.5 18.8 74% 26% 16,46 75% -73,461 Brown 10 1.865,718.20 -3.9% -73,3137 -10.5% -195,900 45-R0.5 18.8 74% 26% 16,46 75% -72,753 16,196 72,753 16,196 </td <td>_</td> <td>0432 0470 0471 5635</td> <td>Structures and improvements Paddy's Run GT 13 Trimble Co 5 Trimble Co 6 Brown 5</td> <td>1,910,327.76 3,566,217.06 3,564,353.91 2,564,353.91</td> <td>6.6.6. 8.6.6. 8.6.6.</td> <td>-74,503 -139,082 -139,010</td> <td>4.3% -3.0%</td> <td></td> <td>-8-2% -6.9% -6.9%</td> <td></td> <td>45-R0.5 45-R0.5 45-R0.5</td> <td>18.8 18.8 18.8</td> <td>74% 74% 74%</td> <td>26% 26% 26%</td> <td>496,685 927,216 926 730</td> <td></td> <td>-74,503 -739,082</td> <td>8.6.6 8.6.6 8.6.0</td>	_	0432 0470 0471 5635	Structures and improvements Paddy's Run GT 13 Trimble Co 5 Trimble Co 6 Brown 5	1,910,327.76 3,566,217.06 3,564,353.91 2,564,353.91	6.6.6. 8.6.6. 8.6.6.	-74,503 -139,082 -139,010	4.3% -3.0%		-8-2% -6.9% -6.9%		45-R0.5 45-R0.5 45-R0.5	18.8 18.8 18.8	74% 74% 74%	26% 26% 26%	496,685 927,216 926 730		-74,503 -739,082	8.6.6 8.6.6 8.6.0
Brown II 483.353.77 -3.9% -19.046 -7.7.8% -135,762 -31.7% -15.4.80 4.5.713 -5.213 Brown B 2.012.64.95 3.39% -19.046 -7.1.8% -135,762 -13.7% -15.4.80 45.70.5 18.8 7.4% 26% 126.972 -5.213 Brown B 2.012.65 45.70.5 18.8 7.4% 26% 126.972 -15% -5.213 Brown 10 1.865.718.20 -3.9% -173.137 -10.5% -95.705 18.8 7.4% 26% 126.972 -15% -78.444 Brown 10 1.865.718.20 -3.9% -17.373 -10.5% -95.00 45.8.05 18.8 7.4% 26% 1.5% -72.763 Brown 10 1.802.556.55 -3.9% -10.5% -195.900 45.8.0.5 18.8 7.4% 26% 1.5% -72.763 Haleling 434.855.66 -3.9% -16.939 -12.2,577 -10.7% -79.2,570 16% -72.753 Haleling <td></td> <td>5636 5636</td> <td>Brown 6 Brown 5</td> <td>133,678.33</td> <td>, 9.6°</td> <td>-29,401</td> <td>-7.4% -81.3%</td> <td></td> <td>-11.3% -85.2%</td> <td></td> <td>45-R0.5 45-R0 5</td> <td>18.8 19.8</td> <td>74%</td> <td>26%</td> <td>196,339</td> <td>-15%</td> <td>-29,451</td> <td>-3.9%</td>		5636 5636	Brown 6 Brown 5	133,678.33	, 9.6°	-29,401	-7.4% -81.3%		-11.3% -85.2%		45-R0.5 45-R0 5	18.8 19.8	74%	26%	196,339	-15%	-29,451	-3.9%
Brown 19 4,641,054.86 -3.9% -181,001 -1.2.0% -2.01,265 45.40.5 18.8 74% 26% 523,290 -15,494 Brown 10 1,865,718.20 -3.9% -181,001 2.5% -301,669 45.40.5 18.8 74% 26% 553, 290 -15% -78,494 Brown 10 1,865,718.20 -3.9% -72,763 6.6% -120,667 -6.5% -301,669 45.40.5 18.8 7.4% 26% 1206,674 -15% -72,753 Brown 11 1,802,596.65 -3.9% -70,301 -6.8% -10.7% -195,901 5.4% 74% 26% 45.66 -72,753 Hafeling 4.34,853.46 -3.9% -16,959 -14.1% -10.7% -192,874 45.40.5 18.8 74% 26% 485,75 -16,930 Hafeling 21,174,956.60 -3.9% -16,959 -14,1% -61,314 -18.0% -78,25 18.8 74% 26% 485,75 -15% -16,930		5638		488,353.77 2,012,654.95	,9% 1,9%	-19,046 -78,494	-27.8% -6.1%		-31.7%		45-R0.5	18.8	74%	26%	34,756 126,972	-15% -15%	-5,213 -19,046	,9.6, %0.6,
Total Account 341 21,174,956.66 -3.9% -72,763 -6.6% -123,137 -10.5% -195,900 45-R0.5 18,8 74% 26% 48.047 -15% -761,001 Brown 11 1,825,565 -3.9% -70,301 -6.8% -122,577 -10.7% -195,907 45-R0.5 18,8 74% 26% 486,75 -15% -72,753 Hafeling 43.4853.46 -3.9% -16,959 -14.1% -61,314 -18.0% -78,274 45-R0.5 18,8 74% 26% 486,75 -15% -70,301 Total Account 341 21,174,956.60 -3.9% -825,823 -5.4% -1,146,853 -9.3% -1,372,675		5639 5640	Brown 9 Brown 10	4,641,054,86	3.9%	-181,001	-2.6%		-10.0%		45-R0.5 45-R0.5	18.8 18.8	74%	26% 26%	523,290		-78,494	-3.9%
21,174,956.60 -3.9% -825,823 -5.4% -1,146,853 -9.3% -1,972,676		5641 5696	Brown 11 Hafeling	1,000,10,295.65 1,802,595.65 434,853.46	%6.6- %6.6- %6.6-	-72,763 -70,301 -16,959	-6.6% -6.8% -14.1%		-10.5% -10.7% -18.0%		45-R0.5 45-R0.5 45-R0.5	18.8 18.8 9	74%	56% 56%	485,087 468,675		-72,763 -72,763 -70,301	8.6% 8.6% 8.6%
			Total Account 341	21,174,956.60	-3.9%	-825,823	-5.4%		%6.0-			0.0	14%	%97	113,062		-16,959	-3.9%

Exhibit___(LK-3)
Page 3 of 5

Kentucky Utilities Electric Division

Summary of Original Cost of Utility Plant in Service and Interim and Terminal Net Salvage

			;		Original			stimated Fut	Estimated Future Net Salvane	đ		Interim	A.1. 0.2.	Interim Re	tirement Rat	Interim Retirement Rate Calculation			
$ \begin{array}{cccccccccccccccccccccccccccccccccccc$			Code		Cost	Interim Ne		Terminal h	let Salvage		let Salvage	Ref	ALRet	Percent	Percent	Retired	Interim Retired	_	nterim Ret. % Of Total
Mathematical and sectors Mathema	Mathematical constraints Mathema	(a)	(a)	(c)	(p)	(e)	(j)	¢ (5)	Amount (h)	% ≘	Amount ()	ASL/Curve (k)	ම දි	XII) S	Retirement	Amount (a)	Rate		Investment
000000000000000000000000000000000000	March (1) March (1) <thmarch (1)<="" th=""> March (1) <thmarch (1)<="" th=""> March (1) <thmarch (1)<="" th=""> <thmarch (1)<="" th=""> <thmar< td=""><td>342.00</td><td></td><td>Fuel Holders, Producers and Accessory</td><td></td><td></td><td></td><td></td><td></td><td></td><td></td><td></td><td></td><td></td><td></td><td></td><td>à</td><td>Ð</td><td>6</td></thmar<></thmarch></thmarch></thmarch></thmarch>	342.00		Fuel Holders, Producers and Accessory													à	Ð	6
010 1000000000000000000000000000000000000	010 10000000 10000000 10000000 10000000000 1		0432	Paddy's Run GT 13	1,975,977.95	-3.2%		4 4%	56 043		1001								
Unit Timelic fere	011 1010		642 871	Trimble Co 5 Trimble Co 6	237,747.79	-3.2%	-7,608	47.3%	-112,455		-130,174		7.12	70%	21%	414,955	-15%	-62,243	-3.2%
9000 100000 100000 100000 100000 100000 100000 100000 1000000 1000000 1000000 1000000 1000000 1000000 1000000 1000000 1000000 10000000 1000000000000000000000000000000000000	Size Description VALUE Size		12	Trimble Co D Trimble Co Dinating	237,623.60	-3.2%	-7,604	47.4%	-112,634		-120,238		217	% 6 J	21%	49,927	%cL-	-7,489	-3.2%
910 910 <td>950 950<td></td><td>5635</td><td></td><td>4,474,853.28</td><td>-3.2%</td><td>-143,195</td><td>-15.0%</td><td>-671,228</td><td></td><td>-814,423</td><td></td><td>217</td><td>%61 %02</td><td>215</td><td>49,901</td><td>%cl-</td><td>-/,485</td><td>-3.2%</td></td>	950 950 <td></td> <td>5635</td> <td></td> <td>4,474,853.28</td> <td>-3.2%</td> <td>-143,195</td> <td>-15.0%</td> <td>-671,228</td> <td></td> <td>-814,423</td> <td></td> <td>217</td> <td>%61 %02</td> <td>215</td> <td>49,901</td> <td>%cl-</td> <td>-/,485</td> <td>-3.2%</td>		5635		4,474,853.28	-3.2%	-143,195	-15.0%	-671,228		-814,423		217	%61 %02	215	49,901	%cl-	-/,485	-3.2%
0000 000000 00000 00000 <th< td=""><td>0 0</td><td></td><td>5636</td><td>Brown 6</td><td>127,929.28</td><td>-3.2%</td><td>-23,294</td><td>-8.2%</td><td>-59,690</td><td></td><td>-82,984</td><td></td><td>21.7</td><td>%64</td><td>21%</td><td>939,719 162 866</td><td>15%</td><td>-140,958</td><td>-3.2%</td></th<>	0 0		5636	Brown 6	127,929.28	-3.2%	-23,294	-8.2%	-59,690		-82,984		21.7	%64	21%	939,719 162 866	15%	-140,958	-3.2%
State State <th< td=""><td>500 50000 5</td><td></td><td>5637</td><td>Brown 7</td><td>140,014,00</td><td>-3.2%</td><td>4,688</td><td>-34.5%</td><td>-50,548</td><td></td><td>-55,236</td><td></td><td>21.7</td><td>%62</td><td>21%</td><td>30,768</td><td>2017 2017</td><td>168,32-</td><td>-3.2%</td></th<>	500 50000 5		5637	Brown 7	140,014,00	-3.2%	4,688	-34.5%	-50,548		-55,236		21.7	%62	21%	30,768	2017 2017	168,32-	-3.2%
State State <th< td=""><td>500 Description 100,000 200 00000 20</td><td></td><td>5638</td><td>Brown 8</td><td>145,745.15</td><td>-3.2%</td><td>4,664</td><td>-71.1%</td><td>-103,625</td><td></td><td>-108,289</td><td></td><td>21.7</td><td>%64</td><td>21%</td><td>30,00</td><td>%C1-</td><td>4,013</td><td>3.2%</td></th<>	500 Description 100,000 200 00000 20		5638	Brown 8	145,745.15	-3.2%	4,664	-71.1%	-103,625		-108,289		21.7	%64	21%	30,00	%C1-	4,013	3.2%
String Biology (String) String String (String) String String (String) String String (String) String String (String) String String (String) String String (String) String String (String) String String (String) String String (String) String String) String) String) String) String) String) String) String)	Stress Stres Stres Stres <td></td> <td>5639</td> <td>Brown 9</td> <td>19,012,08</td> <td>-3.2%</td> <td>-628</td> <td>-665.5%</td> <td>-130,524</td> <td></td> <td>-131,151</td> <td></td> <td>21.7</td> <td>%67</td> <td>21%</td> <td>4 1 10</td> <td>10.01</td> <td></td> <td>-3.2%</td>		5639	Brown 9	19,012,08	-3.2%	-628	-665.5%	-130,524		-131,151		21.7	%67	21%	4 1 10	10.01		-3.2%
Qii I Bonni I Markani M	640 Description 0.0128 3.24 0.1028 5.44 1.1028 1.1028 1.1028 1.1028		5640	Brown 10	44.404'949'E	3.2%	-62,191	-6.7%	-130,211		-192,402		21.7	70%	21%	4/1 13 1/10 10E	9401- 1076		-3.2%
Gib Transition Transitert Transitert Transitert <td>Gib Function Table from Table from</td> <td></td> <td>5641</td> <td>Binwin 11</td> <td>31,/37.96</td> <td>-3.2%</td> <td>-1,016</td> <td>-411.2%</td> <td>-130,506</td> <td></td> <td>-131,522</td> <td></td> <td>21.7</td> <td>%62</td> <td>21%</td> <td>5 1 20 5 665</td> <td>94 CI -</td> <td>6L7'L0-</td> <td>3.2%</td>	Gib Function Table from		5641	Binwin 11	31,/37.96	-3.2%	-1,016	-411.2%	-130,506		-131,522		21.7	%62	21%	5 1 20 5 665	94 CI -	6L7'L0-	3.2%
Gib Homo Train Tr	Gene Homon Training Tr		5645	Brown 9 Pineline	52,429,84	-3.2%	-1,678	-248.9%	-130,498		-132,176		21.7	%62	21%	11 010	/021	000'l-	-3.2%
Tail Account 3Q Tail Accou	Tatk Accord		5696	Hafeling	6,151,151,81 181,132.61	-3.2%	-260,836 -5.796	-15.0% -36.0%	-1,222,670 -65,208		-1,483,506		21.7	%62	21%	1,711,738	-15%	-1,052	-3.2%
Inconcentration 132058115 3.2% 68.429 1.6% 3.66.167 <	Interformer Control (A) Control (A) <thcontrol (a)<="" th=""> <thcontrol (a)<="" th=""></thcontrol></thcontrol>								007'00	0 7.00-	±000'1 /-	12-20	21.7	%67	21%	38,038	-15%	-5,706	-3.2%
0 Prime Prime 200 </td <td>0 1 1 2</td> <td></td> <td></td> <td>rual Account 342</td> <td>18,325,891.25</td> <td>-3.2%</td> <td></td> <td>-16.4%</td> <td>-3,006,739</td> <td>-19.6%</td> <td>-3,593,167</td> <td></td> <td></td> <td></td> <td></td> <td></td> <td></td> <td></td> <td></td>	0 1 1 2			rual Account 342	18,325,891.25	-3.2%		-16.4%	-3,006,739	-19.6%	-3,593,167								
Not Teach T	443 Province 23373 1.94 23373 1.94 23373 1.94 23373 1.94 23373 1.94 23373 1.94 23373 1.94 23373 1.94 23373 1.94 23373 1.94 23373 1.94 23373 1.94 23373 1.94 23373 1.94 233733 1.94 233733 1.94 2337333 1.94 2337333 1.94 234733 1.94 234733 1.94 234733 1.94 234733 1.94 234733 1.94 234733 1.94 234733 1.94 234733 1.94 234733 1.94 234733 1.94 234733 1.94	3.00		Prime Movers															
U17 Timble Co5 239,263/20 0.00 1.5% -424/10 <	010 Timele Cris 2006/2001 010 115 440/3 115 440/3 115 440/3 115 440/3 115 440/3 115 440/3 115 440/3 115 440/3 115 440/3 115 440/3 115 440/3 115 115 440/3 115 115 440/3 115 115 440/3 115 115 440/3 115 440/3 115 440/3 115 440/3 115 440/3 115 440/3 115 440/3 115 440/3 115 440/3 115 440/3 115 440/3 115 440/3 115 440/3 115 440/3 115 440/3 115 440/3 115 440/3 115 440/3 115 115 440/3 115 440/3 115 115 115 115 115 115 115 115 115 115 115 115 115 115 115 115		0432	Paddy's Run GT 13	17 355 293 47	70.0	c	1 007	112 000	ļ									
Q471 Timula Co6 Signature Si	NST Timule Col Zastagezation Optimized Zastagezation Zastagezation Zastagezation Zastagezation Zastagezation Zastagezation Zastagezation <thzastagezation< td="" thz<=""><td></td><td>0470</td><td>Trimble Co 5</td><td>29.842.502.10</td><td>%0.0</td><td></td><td>04.A.1.</td><td>-329,751</td><td>-1.9%</td><td>-329,751</td><td>40-R0.5</td><td>20.8</td><td>20%</td><td>30%</td><td>5,206,588</td><td>%0</td><td>¢</td><td>20 U%</td></thzastagezation<>		0470	Trimble Co 5	29.842.502.10	%0.0		04.A.1.	-329,751	-1.9%	-329,751	40-R0.5	20.8	20%	30%	5,206,588	%0	¢	20 U%
633 Browni 724403223 000 1.33 244743 0.001 0.13 244743 0.001 0.13 244743 0.001 0.13 244743 0.001 0.011 </td <td>635 Promi 7 44/14/14/1 44/14/1 44/14/1</td> <td></td> <td>0471</td> <td>Trimble Co 6</td> <td>29.826.880.91</td> <td>%000</td> <td></td> <td>-1.0% 2</td> <td>447,538</td> <td>-1.5%</td> <td>-447,638</td> <td>40-R0.5</td> <td>20.8</td> <td>70%</td> <td>30%</td> <td>8.952.751</td> <td>%0</td> <td>è</td> <td>0.0%</td>	635 Promi 7 44/14/14/1 44/14/1 44/14/1		0471	Trimble Co 6	29.826.880.91	%000		-1.0% 2	447,538	-1.5%	-447,638	40-R0.5	20.8	70%	30%	8.952.751	%0	è	0.0%
555 Demré 31/31/11,41 ON 31/31/11,41 ON 31/31/31,41 ON 31/31/31,31 ON 30/31,31	953 Brownie 3191/11/15 000 1/3 4/00/2 1/3 4/00/2 0/3		5635		12.440.942.32	%00	0	24 OFC	447,403	-1.5%	447,403	40-R0.5	20.8	%02	30%	8,948,064	%0	• •	0.0%
Sign Brown 7 Sign Stream 7 Sign Stre	3537 Demy 3207.477.51 Control Control <thc< td=""><td></td><td>5636</td><td></td><td>31,591,711,55</td><td>0.0%</td><td>• •</td><td>1 200</td><td>0/0'002-</td><td>-1.9%</td><td>-236,378</td><td>40-R0.5</td><td>20.8</td><td>20%</td><td>30%</td><td>3,732,283</td><td>%0</td><td>•</td><td>%0.0</td></thc<>		5636		31,591,711,55	0.0%	• •	1 200	0/0'002-	-1.9%	-236,378	40-R0.5	20.8	20%	30%	3,732,283	%0	•	%0.0
568 Brown 6 1 5 27% 502.80 7.0% 30% 17.21.44 0% 0 560 Brown 10 1 165.25719.65 0.0% 0 2.7% 50.25.00 0.0% 0 2.7% 50.25.00 0.0% 0 2.7% 50.25.00 0.0% 0 2.7% 50.05.00 0.0% 0 2.7% 50.05.00 0.0% 0 0.0% 0.0% 0.0% 0.0% 0 0.0% 0 0.0% 0.0% 0 0.0% 0 0.0% 0 0.0% 0 0.0% 0 0.0% 0 0.0% 0 0.0% 0 0.0% 0 0.0% 0 0.0% 0 0.0% 0.0% 0 0 0.0% 0 0 0 0.0% 0	Bigs Brownie Bigs Brownie Bigs Brownie Bigs Brownie Bigs Brownie Bigs Bigs </td <td></td> <td>5637</td> <td></td> <td>39 071 447.54</td> <td>0.0%</td> <td></td> <td>-11%</td> <td>-4 ru,032</td> <td>-1.3%</td> <td>410,692</td> <td>40-R0.5</td> <td>20.8</td> <td>70%</td> <td>30%</td> <td>9,477,513</td> <td>%0</td> <td>0</td> <td>%0.0</td>		5637		39 071 447.54	0.0%		-11%	-4 ru,032	-1.3%	410,692	40-R0.5	20.8	70%	30%	9,477,513	%0	0	%0.0
563 Brown 9 202,884 40,805 202,884 40,805 202,884 40,805 202,884 60,80 0	563 Brown 9 500, who 10 500,		5638	Brown 8	18.625.319.58	%00	• =	24 - 1- 1- V	00/'67t	%L'L-	-429,786	40-R0.5	20.8	%04	30%	11,721,434	%0	0	0.0%
560 Demon 10 18,000,066.60 0.0% 2.7% 5670,00 1.0% 3.0% 5.02,400 0.% 0 10al Account 343 231,730,032,823 0.0% 0 -1.7% -30,4079 -1.7% -307,60 0.40,055 0.0% 0 -1.7% -30,4079 0.% 0 0.% 0 0.% 0 -1.7% -43,4079 0.% 0.% 0 0.% 0 -1.7% -43,4079 0.% 0 0.% 0 0.% 0 0.% 0 0.% 0 -1.7% -43,4079 0.% 0.% 0 0.% 0 0.% 0 0.% 0 0.% 0 0.% 0 0.% 0 0.% 0 0.% 0 0.% 0 0 0.% 0 0 0.% 0 0.% 0 0.% 0 0 0.% 0 0.% 0 0.% 0 0.% 0 0.% 0 0.% <td< td=""><td>3640 Bown 10 16,00,066.6 0.0% 0 27% 54% 10 70% 30% 55,23,40 0.% 0 46 Tolah Acutor 1,5% 57,70 1,5% 57,70 4,57,71 4,57,70 4,57,70</td><td></td><td>5639</td><td>Brown 9</td><td>20,674,801.66</td><td>0.0%</td><td>• c</td><td>04. J. 7-</td><td>-202,564</td><td>%/7</td><td>-502,884</td><td>40-R0.5</td><td>20.8</td><td>70%</td><td>30%</td><td>5,587,596</td><td>%0</td><td>0</td><td>%00</td></td<>	3640 Bown 10 16,00,066.6 0.0% 0 27% 54% 10 70% 30% 55,23,40 0.% 0 46 Tolah Acutor 1,5% 57,70 1,5% 57,70 4,57,71 4,57,70 4,57,70		5639	Brown 9	20,674,801.66	0.0%	• c	04. J. 7-	-202,564	%/7	-502,884	40-R0.5	20.8	70%	30%	5,587,596	%0	0	%00
Beth Brown 11 33,060,0263.23 0.0% 0 1.7% -30,000 45,700 47,000 2.0.8 70% 30% 9,915,003 0% Total Account 343 251,730,024.10 0.0% 0 -1.7% -30,4079 -1.7% -30,4079 -1.7% -30,4079 -0.7% -30,4079 0% -3015,000 0% -3015,000 0% -3015,000 0% -3015,000 0% -3015,000 0% -3015,000 0% -3015,000 0% -3015,000 0% 0% -3015,000 0% -3015,000 0% -3015,000 0% -3015,000 0% -3015,000 0% -3015,000 0% 0% -3015,000 0% -3015,000 0% -3015,000 0% -3015,000 0% -3015,000 0% -3015,000 0% -3015,000 0% -3015,000 0% -3015,000 0% -3015,000 0% -3015,000 0% -3015,000 0% -3015,000 0% -3015,000 -3015,000	Beth Bown I 30500262.23 Oth 7 3050025 0.0 0 1.75 307000 1.75 307000 0.0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 1.75 30700 0.44000 0		5640	Brown 10	18,800,096.69	0.0%) C	N 1 7-	-507 603	-2.4% 2.79/	-496,195	40-R0.5	20.8	70%	30%	6,202,440	%0	0	%0.0
Tala Account 343 Ze1.279.024.10 0.0% -1.7% -3.304.079 -1.0% -0.0% <t< td=""><td>Tala Account 343 Tala Account 344 <thtala 344<="" account="" th=""> <thtala 344<="" account="" t<="" td=""><td></td><td>5641</td><td>Brown 11</td><td>33,050,028.28</td><td>0.0%</td><td>0</td><td>-1.5%</td><td>-307,003</td><td>-1.5%</td><td>-507,603</td><td>40-R0.5</td><td>20.8</td><td>%02 70%</td><td>30%</td><td>5,640,029</td><td>%0</td><td>0</td><td>0.0%</td></thtala></thtala></td></t<>	Tala Account 343 Tala Account 344 Tala Account 344 <thtala 344<="" account="" th=""> <thtala 344<="" account="" t<="" td=""><td></td><td>5641</td><td>Brown 11</td><td>33,050,028.28</td><td>0.0%</td><td>0</td><td>-1.5%</td><td>-307,003</td><td>-1.5%</td><td>-507,603</td><td>40-R0.5</td><td>20.8</td><td>%02 70%</td><td>30%</td><td>5,640,029</td><td>%0</td><td>0</td><td>0.0%</td></thtala></thtala>		5641	Brown 11	33,050,028.28	0.0%	0	-1.5%	-307,003	-1.5%	-507,603	40-R0.5	20.8	%02 70%	30%	5,640,029	%0	0	0.0%
Instructure 25/27/9/04.10 0.0% 1.7% 4.304.073 2.77 2.77 2.77 2.77 2.77 2.77 2.77 2.77 2.77 2.74 2.77 2.74 2.77 2.77 2.77 2.74 2.77 2.74 2.77 2.74 2.77 2.77 2.74 2.77 2.74 2.77 2.74 2.77 2.74 2.74 2.74 2.74 2.74	$ \begin{array}{cccccccccccccccccccccccccccccccccccc$										001001	0.02-04	2U.5	%07	30%	9,915,008	%0	0	%0.0
Concretions Concretions State and the concretions <td></td> <td></td> <td></td> <td>-</td> <td>co1,279,024.10</td> <td>0.0%</td> <td>0</td> <td>-1.7%</td> <td>4,304,079</td> <td>-1.7%</td> <td>4,304,079</td> <td></td> <td></td> <td></td> <td></td> <td></td> <td></td> <td></td> <td></td>				-	co1,279,024.10	0.0%	0	-1.7%	4,304,079	-1.7%	4,304,079								
Wd2 Padvis Run GT 13 5185/636:1 -0.2% -10.371 6.5% -37.488 -7.78 -7.78 -7.78 -7.78 -7.78 -7.78 -7.78 -7.78 -7.78 -7.78 -7.78 -7.78 -7.78 -7.78 -7.78 -7.78 -7.78 -7.78 -7.48 -7.71 -7.48 -7.71 -7.48 -7.71 -7.48 -7.71 -7.48 -7.71 -7.48 -7.71 -7.48 -7.71 -7.48 -7.71 -7.48 -7.71 -7.48 -7.71 -7.48 -7.71 -7.48 -7.71 -7.48 -7.71 -7.48 -7.71 -7.48 -7.47 -7.48 -7.71 -7.48 -7.71 -7.48 -7.71 -7.48 -7.71 -7.48 -7.71 -7.48 -7.71 -7.48 -7.71 -7.48 -7.71 -7.48 -7.71 -7.48 -7.71 -7.48 -7.71 -7.48 -7.41 -7.48 -7.41 -7.48 -7.41 -7.41 -7.41 -7.41 -7.41 -7.41	M03 Timble Cols 5,165,656,11 0.2% -10371 6.5% -37,066 6.7% -34,438 2.7% -36 5602 0471 Timble Cols 3,734,4533 0.2% -7465 -117% 456 -117% 4566 -7,445 -117% 4566 -7,445 -117% 4566 -7,445 -117% 4566 -7,445 -117% 4566 -7,445 -117% 4566 -7,445 -117% 4566 -7,445 -117% 4566 -7,445 -117% 4566 -7,445 -117% 4566 -7,445 -117% 4566 -7,446 -11,37 27,39 97% 3% 11,1794 -5% 5,569 563 Brown 1 3722/3846 0.2% -7,346 -10,3% -2339 97% 3% 11,1794 -5% 5,569 563 Brown 1 3722/3846 0.2% -7,446 -10,3% -51,212 2476 239 97% 3% 111,394 -7,413 5	4.00		Generators															
QH70 Timble Co5 373,4/23;8 0.2% 7,466 11.7% 446,826 12.1 23.1 97% 3% 155,69 -5% -7778 5635 Brown 6 373,448,71 0.2% 7,466 -11.7% 440,68 2.78 2.39 97% 3% 115,013 -5% -5,002 5635 Brown 6 377,2619,52 0.2% 7,466 -11.7% 436,696 -19% 3% 115,173 -5% -5,693 5635 Brown 6 377,2619,52 0.2% -7,465 -11.3% -430,664 2.78 2.39 97% 3% 11,137 -5% -5,669 5638 Brown 7 377,2619,52 0.2% -7,446 -11.3% -420,57 2.39 97% 3% 11,137 -5% -5,669 5638 Brown 9 5,45,2040,97 0.2% -7,446 -11.3% -420,17 0.2% -7,421 12% -7,421 12% -7,433 -7,416 -11.3% -426,123	$ \begin{array}{cccccccccccccccccccccccccccccccccccc$			Paddy's Run GT 13	5,185,636,11	-0.2%	-10.371	5 5 Q	337 766	791 1									
G471 Timble Co6 3722,468.71 -0.2% 7,465 11.7% 7445 11.1% 7445 11.1% 7451 11.1% 7451 11.1% 7451 11.1% 7451 11.1% 7451 11.1% 7451 11.1% 7451 11.1% 7451 11.1% 7451 11.1% 7451 11.1% 7451 11.1% 7451 11.1% 7451 11.1% 7451 11.1% 7451 11.1% 7451 11.1%	647 Timble Co6 3732,488.71 0.2% 7,465 111.7% 444,166 233 97% 3% 112,033 5% 5,605 6535 Brown 5 2.27,258 4.27 7,465 11.7% 436,699 11.9% 444,164 2.7% 3% 111,379 5% 5,605 6535 Brown 5 3.772,615.23 0.2% 7,446 11.3% 420,694 27% 3% 111,379 5% 5,669 6538 Brown 9 3.772,615.33 0.2% 7,446 11.3% 420,694 27% 3% 111,379 5% 5,669 6538 Brown 19 3.772,615.33 0.2% 7,446 11.3% 420,617 27.9 3% 111,379 5% 5,669 6548 Brown 19 3.772,613.7 0.2% 7,446 11.3% 420,64 27.8 23.9 97% 3% 111,1379 5% 5,453 6541 Brown 19 5,447,616 27.8 23.9 97% 3% 111,1379 5% 7,451 6541 Brown 19		_	Trimble Co 5	3,734,423.83	-0.2%	-7.469	-11 7%	000, /cc-	%	-347,438	42-R5	23.9	61%	3%	155,569	-5%	-7,778	-0.2%
5535 Brown 5 2,831,528.33 0.2% -563 4.2% -241,44 4.2% 5.53 9.7% 3% 11,974 -5% 5.50 5633 Brown 6 3,772,619,52 0.2% 7,425 11,4% 420,664 4275 23.9 97% 3% 11,1374 -5% 5.56 5633 Brown 6 3,772,619,52 0.2% 7,425 11,4% 420,664 4275 23.9 97% 3% 11,1374 -5% 5.564 5633 Brown 1 3,772,619,52 0.2% -10,904 -9.3% -507,040 9.5% -517,944 4275 23.9 97% 3% 111,379 5% -5,584 5641 Brown 10 5,472,040,37 0.2% -0,3143 -90% -517,944 4275 23.9 97% 3% 116,619 5% -5,584 7,417 5641 Brown 11 5,187,040.30 0.2% -10,344 -5% 5,1744 2775 23.9 97%	5535 Brown 5335 Brown 5339 S330 S34113 S347 S451 S457 S453 S4533 S453 S4533			Trimble Co 6	3,732,468,71	-0.2%	7 465	11 7%	076'00L	11.07/0	0.55,444	4Z-K5	23.9	97%	%E	112,033	-5%	-5,602	-0.2%
5536 Brown 6 3,712,619.5 0.2% 7,425 1.1.3% 4.2.47 5.3.9 9.7% 3.8 64,946 -5% 4.2.47 5537 Brown 7 3,722,786.46 0.2% 7,446 11.13% 4.2.475 2.3.9 9.7% 3.8 111,664 -5% -5,569 5537 Brown 8 4,563,060 0.2% 7,446 11.3% 4.23,239 11,6% 4.26,17 2.2% 9.7% 3% 11,1684 -5% -5,569 56338 Brown 10 5,420,040,37 0.2% -10,908 -10,2% -506,331 -10,4% -515,21 4.2.45 23.9 97% 3% 11,1684 -5% -7,431 5641 Brown 10 4,944,627.1 0.2% -10,3% -506,331 -10,4% -515,512 42.45 23.9 97% 3% 165,619 -5% -7,431 5694 Hafeling 4,000.50 -2% -0,331 -10,4% -575,21 42.45 23.9 97%	5536 Brown 6 3,712,619,52 0,2% 7,4% 11,4% -20,1% 7,4% 11,4% -20,1% 7,4% 2,47 2,47 2,47 3,71 11,37 5% 5,58<			Brown 5	2,831,528,33	-0.2%	-5 663	20 B	301001	W A' I I -	444'104	42-K5	23.9	97%	3%	111,974	-5%	-5.599	-0.2%
537 Brown 7 3,722,788.46 0.2% 7,446 11.3% -5.569 53.8 111,379 -5% -5.569 533 Brown 10 3,722,788.46 0.2% -7,446 11.3% -20,004 -26% -5,569 -5,569 533 Brown 10 5,485,360.72 0.2% -9,008 -10,2% -50,5304 -10,4% 515,212 42.765 23.9 97% 3% 111,379 -5% -5,569 5640 Brown 10 5,187,040 9.5% -516,271 42.765 23.9 97% 3% 116,84 -5% -7,417 5641 Brown 10 4,944,422.71 0.2% -10,374 -9.7% -504,331 10,4% 515,212 42.765 23.9 97% 3% 116,84 -5% -7,417 5641 Brown 10 4,944,422.71 0.2% -10,374 -9.7% -504,311 42,655 23.9 97% 3% 155,611 -5% -7,417 5551 Helling 47,479 -53,449 -5.5% -261,450 42,655,019 97% 3%	533 Brown 7 3,722,788.46 0.2% 7,446 -11.3% -430.004 42.45 2.39 97% 3% 111379 -5% -5,669 5333 Brown 8 5,422,778.46 0.2% -7,446 -11.3% -420.057 -11.5% -420.057 -11.3% -5.69 97% 3% 111364 -5% -5.68 5633 Brown 10 5,452,040.37 -0.2% -9008 -10.2% -50,304 -10.4% -51,511 2.745 2.39 97% 3% 111364 -5% -7,413 5640 Brown 10 5,452,040.30 0.2% -10.374 -9.7% -51,511 2.745 2.39 97% 3% 1146.133 5% -7,413 5641 Brown 11 5,187,040.30 0.2% -10.374 -9.7% -513,517 2.745 2.39 97% 3% 146.133 5% -7,417 5641 Brown 11 5,187,040.30 0.2% -10.374 -6.5% -561,495 2.31 97% 3% 155,661 5% -7,417 5631 Totttt <td></td> <td></td> <td>Brown 6</td> <td>3,712,619,52</td> <td>-0.2%</td> <td>-7.425</td> <td>-11.4%</td> <td>001,202-</td> <td>6.4% 24.0 24.0</td> <td>-237,848</td> <td>42-R5</td> <td>23.9</td> <td>97%</td> <td>3%</td> <td>84,946</td> <td>-5%</td> <td>4,247</td> <td>-0.2%</td>			Brown 6	3,712,619,52	-0.2%	-7.425	-11.4%	001,202-	6.4% 24.0 24.0	-237,848	42-R5	23.9	97%	3%	84,946	-5%	4,247	-0.2%
5638 Brown 8 4,953,960.72 0.2% 9,000 11.0% 428,121 42.45 2.39 97% 3% 111,684 5% 5,584 5639 Brown 9 5,452,000.37 0.2% -10,904 -9.3% -507,040 -9.5% -7,131 -2.45 2.39 97% 3% 111,684 -5% -7,431 5641 Brown 10 5,452,040.37 -0.2% -10,904 -9.3% -501,331 -10,4% -514,220 42.75 2.39 97% 3% 163,561 -5% -7,417 5641 Brown 11 5,447 0.2% -10,344 -574,220 42.755 2.39 97% 3% 163,561 -5% -7,781 5641 Brown 13 4,7479,932.03 -0.2% -9,046 -5.3% -4,175 3% 163,561 -5% -7,781 5641 Brown 13 4,7479,932.03 -0.2% -9,4960 -5% -5,14,264 42.455 2.33 97% 3% 120,690	5638 Brown 8 4,963,960.72 -0.2% -9,003 -11.3% -4,28,171 4,2455 23.9 97% 3% 11,164 5% -5,584 5640 Brown 10 5,452,040.37 -0.2% -10,904 -9.3% -505,301 -10,4% -515,212 42.455 23.9 97% 3% 143,619 -5% -7,417 5641 Brown 10 5,147,402.30 -0.2% -10,374 -9.7% -514,204 3% 143,333 -5% -7,417 5641 Brown 11 5,1187,402.30 -0.2% -10,374 -9.7% -514,204 3% 143,333 -5% -7,417 5641 Brown 13 4,743,932.03 -0.2% -10,4% -515,212 42.45 23.9 97% 3% 155,611 -5% -7,417 5634 Hafeling -1,473,432.03 0.2% -5,34,49 -6.5% -6,165,019 -7% -7,341 5634 -6,56,019 -6,5% -6,166,019 -6,5% -6,165,019 <td></td> <td></td> <td>Brown 7</td> <td>3.722.788.46</td> <td>-0.2%</td> <td>-7 446</td> <td>11 200</td> <td>229.024</td> <td></td> <td>430,004</td> <td>42-R5</td> <td>23.9</td> <td>97%</td> <td>3%</td> <td>111,379</td> <td>-5%</td> <td>-5,569</td> <td>-0.2%</td>			Brown 7	3.722.788.46	-0.2%	-7 446	11 200	229.024		430,004	42-R5	23.9	97%	3%	111,379	-5%	-5,569	-0.2%
5639 Brown 9 5,452,040;97 -0.2% -10,504 -3.3% -001,212 42-H5 2.39 97% 3% 148,619 -5% -7,431 5640 Brown 10 4,944,422,71 -0.2% -9,889 -10,374 -9.7% -517,344 27,75 2.39 97% 3% 156,611 -5% -7,431 5641 Brown 10 5,144,422,71 -0.2% -9,046 -5.3% -501,449 57,17,44 27,15 23.9 97% 3% 156,611 -5% -7,417 5646 Hateling 5,17,344 -6.5% -261,495 42,77 -0.2% -9,034 -10,4% 57,17,44 27,120 42,75 23.9 97% 3% 156,611 -5% -7,417 5696 Hateling 5,17,444 -6.5% -261,495 42,775 23.9 97% 3% 156,611 -5% -7,417 5694 Hateling 4,7,479,932.03 -0.2% -9,046 -5.3% -261,455 42,785 23.9 97% 3% 156,610 -5% -7,417	5639Brown 9 $5,452$ (batr) 97 -1236 $-10,504$ -3376 $-507,240$ $-10,476$ $-517,244$ 2.748 23.9 97% 336 $148,619$ -566 $-7,431$ 5640Brown 10 $4,044,422,71$ -02% $-9,034$ $-9,3\%$ $-507,240$ $-517,244$ 2.748 -33 $163,561$ -5% $-7,431$ 5641Brown 10 $4,044,422,71$ -02% $-9,046$ $-6,3\%$ $-507,449$ $5.77,944$ 2.748 23.9 97% 3% $168,613$ -5% $-7,431$ 5641Brown 10 $4,044,22,71$ -02% $-9,046$ $-6,3\%$ $-553,449$ $-513,517$ 42.755 23.9 97% 3% $168,613$ -5% $-7,431$ 5694Hafeling $1,749,320,02,37$ -02% $-9,04,64$ $-6,3\%$ $-233,449$ $-5,5\%$ $-24,66,059$ $-39,767$ $-39,501$ $-24,66,059$ -5% $-7,471$ 5634Paddy Run GT 13 $2,765$ $-9,04,64$ $-1,6\%$ $-4,656,019$ $-6,5\%$ $-4,656,019$ -5% $-39,301$ -16% -39% $-4,656,019$ -5% $-24,66,320,01$ $-9,7\%$ $-39,301$ $-16,6\%$ $-39,3201$ -30% $-4,656,019$ -5% $-39,301$ -16% -39% $-4,656,019$ -5% $-24,66,320,01$ $-9,7\%$ $-39,3201$ $-16,6\%$ $-16,6\%$ $-16,6\%$ $-16,6\%$ $-16,6\%$ $-16,6\%$ $-16,6\%$ $-16,6\%$ $-16,6\%$ $-16,6\%$ $-16,6\%$ $-16,6\%$ $-16,6\%$ -16			Brown 8	4.953.960.72		900 D-	-10.9% -10.9%	5/0'07t-	-11.3%	428,121	42-R5	23.9	97%	3%	111,684	-5%	-5.584	-0.2%
S40 Brown 10 4,944,422.71 0.2% 9,643 10.3% 0.1,044 2.2H5 0.3 9.7% 3% 163,561 -5% -8,178 5641 Brown 10 5,187,040.30 0.2% -10.374 -9.7% -501,349 42.H5 23.9 97% 3% 163,561 -5% -7,711 5641 Brown 11 5,187,040.30 0.2% -10.374 -9.7% -501,349 42.H5 23.9 97% 3% 156,611 5% -7,711 5187 Taleling 4,7479,332.03 -0.2% -90,46 -6.3% -553,449 6.5% -561,495 42.H5 23.9 97% 3% 120,690 -5% -7,71 17 ki ki ki ki 47,479,332.03 -0.2% -94,960 -9.6% -4,655,019 2.4 -560,165 -39,301 16,6% -5,156 2.3 99% 2,0,59 -5% -7,761 Accessory Electric Equipment 2.446 0.0% -1,6% -39,301 1,6% -39,301	540 Brown 10 4,944,422,71 -0.2% -9,643 T/1,944 42-H5 53,9 97% 3% 163,561 -5% -8,178 5641 Brown 10 5,187,040:30 -02% -10,2% -504,311 -2.75 23,9 97% 3% 155,611 -5% -7,741 5541 Brown 11 5,187,040:30 -02% -10,374 -9.7% 501,495 42-H5 23,9 97% 3% 156,611 -5% -7,741 5541 Brown 13 4,7479,32003 -02% -10,374 -9.7% -501,495 42-H5 23,9 97% 3% 156,611 -5% -7,711 5541 Brown 13 4,7479,32203 -0.2% -9,4960 -9.6% -553,449 4565,019 -7,81 -7,81 -7,781 70catestory Brown 20 -9.7% -9,949.05 -9.8% -4,655,019 -7,81 -7,81 -7,81 -7,81 -7,81 -7,81 -7,81 -7,81 -7,81 -7,81 -			Brown 9	5,452,040.97	-0.2%	-10 904	% Z /0	-303,504	-10.4%	-515,212	42-R5	23.9	%16	3%	148,619	-5%	-7,431	-0.2%
5641 Brown 11 5,187,040.30 -02% -10.374 -0.78 -004.31 -11.47% -03.42.10 22.49 97% 3% 148.333 -5% -7,417 5696 Hafeling 4,023,002.37 -0.2% -10.374 -17.8 -513,517 42.F5 23.9 97% 3% 156,611 -5% -7,417 5696 Hafeling 4,023,002.37 -0.2% -90,66 -5.% -514,495 42.F5 23.9 97% 3% 126,660 -5% -7,417 701al Account 344 47,479,332.03 -0.2% -94,960 -9.6% -4,560,059 -9.8% -4,655,019 -7,8 -7,417 Accessory Electric Equipment 2,466,320.01 0.0% -9.6% -4,560,059 -9.8% -4,655,019 -5% -7,417 Accessory Electric Equipment 2,466,320.01 0.0% -1.6% -3.9,301 -16% -3.9,301 -5.6% 23.3 98% 2% 49,126 0% -7,417 Accessory Electric Equipment	5641 Brown 11 5,187,040.30 0.2% -10,374 9.7% -504,220 2.39 9.7% 3% 148,333 -5% -7,417 5696 Hateling 4,023,002.37 0.2% -10,374 9.7% -513,517 2.789 3% 148,333 -5% -7,417 5696 Hateling 4,023,002.37 0.2% -9,046 6.3% -260,495 4.785 2.39 97% 3% 156,610 -5% -7,417 701al Account 47,479,932.03 0.2% -94,960 -9.6% -4,655,019 2.39 97% 3% 120,690 -5% -7,417 Accessory Elactric Equipment Accessory Elactric Equipment 2.456,3061 -5% -39,301 1.6% -39,301 1.6% -39,301 4,655,019 -5% 27,18 -31,23 98% 2% 49,126 0% -7,417 Accessory Elactric Equipment 2.456,5019 -30,301 45,855,019 -30,301 46,827 -30,301 47,82 23,33 98%			Brown 10	4,944 422 71	-0.2%	9 840	10.2%	2010 231	- A.D.A.	446,710-	42-R5	23.9	91%	3%	163,561	-5%	-8,178	-0.2%
5656 Haleling 4.023,002.37 -0.2% -5.3% -5.3% -13,511 42-H5 2.3.9 97% 3% 155,611 -5% -7,781 Total Account 344 47,479,332.03 -0.2% -94,960 -9.6% 4,550,059 -9.8% -4,655,019 23.9 97% 3% 120,690 -5% -6,035 Total Account 344 47,479,332.03 -0.2% -94,960 -9.6% 4,550,059 -9.8% -4,655,019 23.9 97% 3% 120,690 -5% -6,035 Accessory Electric Equipment 47,479,332.03 -0.2% -9.6% -4,550,059 -9.8% -4,655,019 -5% -6,035 -6,035 -6,035 -6,035 -6,035 -6,035 -6,035 -6,035 -6,035 -6,035 -6,035 -6,035 -7,781 -7,781 -7,781 -7,781 -7,782 -7,781 -7,781 -7,781 -7,782 -7,782 -7,782 0% 0% 0% 0% 0% 0% 0% 0% 0% 0% 0% 0% 0% 0% 0% 0% 0% <t< td=""><td>5556 Haleling 4.023,002.37 0.2% 6.046 6.3% -03,511 42-Hb 23.9 97% 3% 155,611 -5% -7,781 Total Account 344 47,479,932.03 0.2% -96,059 -9.6% -56,149 6.5% -56,1496 42-H5 23.9 97% 3% 126,661 -5% -7,781 Total Account 344 47,479,932.03 0.2% -94,960 -9.6% 4,565,019 -3.1,5.11 42,655,019 23.9 97% 3% 120,660 -5% -7,781 Accessory Electric Equipment Accessory Electric Equipment 2.456,320,01 0.0% -1,6% -39,301 1,655,019 -39,301 45,65,019 -30,301 45,65,019 -30,301 45,65,019 -5% 49,927 -30% -49,927 49,927 47,65 23.3 98% 2% 49,126 0% 0 -1,6% 0% 0 -7,781 17,74 17,745 23.3 98% 2% 49,126 0% 0% 0 0%</td></t<> <td></td> <td>_</td> <td>Brown 11</td> <td>5,187,040.30</td> <td>-0.2%</td> <td>-10.374</td> <td>0.7%</td> <td>-201,400-</td> <td>% 0 0</td> <td>-514,220</td> <td>42-R5</td> <td>23.9</td> <td>87%</td> <td>3%</td> <td>148,333</td> <td>-5%</td> <td>-7.417</td> <td>-0.2%</td>	5556 Haleling 4.023,002.37 0.2% 6.046 6.3% -03,511 42-Hb 23.9 97% 3% 155,611 -5% -7,781 Total Account 344 47,479,932.03 0.2% -96,059 -9.6% -56,149 6.5% -56,1496 42-H5 23.9 97% 3% 126,661 -5% -7,781 Total Account 344 47,479,932.03 0.2% -94,960 -9.6% 4,565,019 -3.1,5.11 42,655,019 23.9 97% 3% 120,660 -5% -7,781 Accessory Electric Equipment Accessory Electric Equipment 2.456,320,01 0.0% -1,6% -39,301 1,655,019 -39,301 45,65,019 -30,301 45,65,019 -30,301 45,65,019 -5% 49,927 -30% -49,927 49,927 47,65 23.3 98% 2% 49,126 0% 0 -1,6% 0% 0 -7,781 17,74 17,745 23.3 98% 2% 49,126 0% 0% 0 0%		_	Brown 11	5,187,040.30	-0.2%	-10.374	0.7%	-201,400-	% 0 0	-514,220	42-R5	23.9	87%	3%	148,333	-5%	-7.417	-0.2%
Total Account 344 47,479,932.03 0.2% -94,960 -9.6% 4,565,019 -2.33 97% 3% 120,690 -5% -6,035 Accessory Electric Equipment Accessory Electric Equipment 2.33 99% 2.4,565,019 -3% 120,690 -5% -6,035 Accessory Electric Equipment 2,466,220.01 0.0% 0 -1.6% -39,301 1.6% -39,301 4,555,019 23.3 99% 2% 49,126 0% 0 Out71 Trimble Co 1,664,234,64 0.0% 0 -1.6% -39,301 45,875 23.3 98% 2% 49,126 0% 0 0471 Trimble Co 1,566,3365,166,84 0.0% 0 -1.6% -39,301 45,875 23.3 98% 2% 33,285 0% 0% 0 5635 Brown 5 1,354,816,11 0.0% 0 -1.2% -49,271 45,875 23.3 98% 2% 75,06 0% 0% 0	Total Account 344 47,479,932.03 0.2% -94,960 -9.6% 4,665,019 -0.3% 120,690 -5% -6,035 Accessory Electric Equipment Accessory Electric Equipment 2.456,320.01 0.0% 0 -1.6% -39,301 -1.6% -39,301 4,655,019 -5% 4,9126 0% 0 0470 Timble Co 5 1.664,324.64 0.0% 0 -1.6% -39,301 4,575 23.3 98% 2% 49,126 0% 0 0471 Timble Co 5 1.664,324.64 0.0% 0 -3.0% -49,927 3.0% 49,927 45,85 23.3 98% 2% 49,126 0% 0 5635 Brown 5 1.354,816.11 0.0% 0 -1.2% -27,182 -1.2% 27,182 0% 0% 0 0% 0% 0 0% 0% 0% 0% 0% 0% 0% 0% 0% 0% 0% 0% 0% 0% 0% 0% <td></td> <td>_</td> <td>Hafeling</td> <td>4,023,002.37</td> <td>-0.2%</td> <td>-8,046</td> <td>-6.3%</td> <td>-253.449</td> <td>20.02 20.02 20.02</td> <td>-261 405</td> <td>42-K5 42 DE</td> <td>53.9 53.9</td> <td>87% 97%</td> <td>3% 0</td> <td>155,611</td> <td>-5%</td> <td>-7,781</td> <td>-0.2%</td>		_	Hafeling	4,023,002.37	-0.2%	-8,046	-6.3%	-253.449	20.02 20.02 20.02	-261 405	42-K5 42 DE	53.9 53.9	87% 97%	3% 0	155,611	-5%	-7,781	-0.2%
I offait Account 344 47,479,332.03 -0.2% -94,960 -9.6% 4,656,019 Accessory Electric Equipment Accessory Electric Equipment 47,479,332.03 -0.2% -94,960 -9.6% 4,656,019 Accessory Electric Equipment Accessory Electric Equipment 2,456,320.01 0.0% 0 -1.6% -39,301 -1.6% -39,301 45.85 23.3 98% 2% 49,126 0% 0 Acressory Electric Equipment 2,456,320.01 0.0% 0 -1.6% -39,301 45.85 23.3 98% 2% 49,126 0% 0 Acressory Electric Equipment 2,456,3365.16 0.0% 0 -3.0% -49,927 3.0% 23.3 98% 2% 49,126 0% 0 Acressory Electric Equipment 2,565 1663,4364.64 0.0% 0 -3.0% -49,927 45.855 23.3 98% 2% 49,126 0% 0 5635 Brown 5 2,565,166.46 0.0% 0 -3.6% -49,77	Iotal Account 34 47,479,332.03 -0.2% -94,960 -9.6% 4,656,019 Accessory Electric Equipment Accessory Electric Equipment 47,479,332.03 -0.2% -94,960 -9.6% 4,656,019 Accessory Electric Equipment Accessory Electric Equipment 2456,320.01 0.0% 0 -1.6% -39,301 -1.6% -39,301 45.R5 23.3 96% 2% 49,126 0% 0 0471 Trimble Co 6 1,664,224,64 0.0% 0 -3.0% -49,927 45.R5 23.3 96% 2% 49,126 0% 0 0471 Trimble Co 6 1,664,224,64 0.0% 0 -3.0% -49,927 45.R5 23.3 96% 2% 33,287 0% 0 5635 Brown 6 1,354,816,11 0.0% 0 -1.2% -27,182 -1.2% -27,182 0% 2% 45,303 0% 0% 0 5635 Brown 6 1,354,816,11 0.0% 0 -1.2%		,							200	024107-	CN-7+	23.9	9/ <i>%</i>	3%	120,690	-5%	-6,035	-0.2%
Accessory Electric Equipment Accessory Electric Equipment 04:32 Paddys Run GT 13 2.456.320.01 0.0% 0 -1.6% -39.301 45-R5 23.3 98% 2% 49.126 0% 0 04:70 Timble Co 5 1.683.3365.16 0.0% 0 -1.6% -39.301 45-R5 23.3 98% 2% 49.126 0% 0 04:71 Timble Co 5 1.683.365.15 0.0% 0 -3.0% -49.927 -3.0% -49.927 45-R5 23.3 98% 2% 33.285 0% 0 5635 Brown 5 2.2865.166.40 0.0% 0 -1.2% -27.182 45-R5 23.3 98% 2% 33.267 0% 0 5636 Brown 6 1.354,816.11 0.0% 0 -3.6% -48,773 -3.5% -243.773 45-R5 23.3 98% 2% 75.30% 0% 0 5636 Brown 6 1.354,816.11 0.0% 0 <td>Accessory Electric Equipment Accessory Electric Equipment 0470 Timmle Co 5 1654,234.64 0.0% 0 -1.6% -39,301 45-R5 23.3 99% 2% 49,126 0% 0 0470 Timmle Co 5 1664,234.64 0.0% 0 -1.6% -39,301 45-R5 23.3 99% 2% 49,126 0% 0 0471 Timmle Co 6 1664,234.64 0.0% 0 -3.0% -49,927 -3.0% 49,927 45-R5 23.3 98% 2% 0 0 0471 Timmle Co 6 1,665,166.84 0.0% 0 -3.0% -49,901 45-R5 23.3 98% 2% 45,303 0% 0 5635 Brown 6 1,354,816.11 0.0% 0 -1.2% -27,182 -1.2% -27,132 45-R5 23.3 98% 2% 45,303 0% 0% 0 5635 Brown 6 1,354,816.11 0.0% 0 -1</td> <td></td> <td></td> <td></td> <td>47,479,932.03</td> <td>-0.2%</td> <td>-94,960</td> <td>-9.6%</td> <td>4,560,059</td> <td>-9.8%</td> <td>4,655,019</td> <td></td> <td></td> <td></td> <td></td> <td></td> <td></td> <td></td> <td></td>	Accessory Electric Equipment Accessory Electric Equipment 0470 Timmle Co 5 1654,234.64 0.0% 0 -1.6% -39,301 45-R5 23.3 99% 2% 49,126 0% 0 0470 Timmle Co 5 1664,234.64 0.0% 0 -1.6% -39,301 45-R5 23.3 99% 2% 49,126 0% 0 0471 Timmle Co 6 1664,234.64 0.0% 0 -3.0% -49,927 -3.0% 49,927 45-R5 23.3 98% 2% 0 0 0471 Timmle Co 6 1,665,166.84 0.0% 0 -3.0% -49,901 45-R5 23.3 98% 2% 45,303 0% 0 5635 Brown 6 1,354,816.11 0.0% 0 -1.2% -27,182 -1.2% -27,132 45-R5 23.3 98% 2% 45,303 0% 0% 0 5635 Brown 6 1,354,816.11 0.0% 0 -1				47,479,932.03	-0.2%	-94,960	-9.6%	4,560,059	-9.8%	4,655,019								
Pradovs kun GT 13 2,456,320.01 0.0% 0 -1.6% -39,301 -1.6% -39,301 45-R5 23.3 99% 2% 49,126 0% 0 Timble Co 5 1.663,432,446 0.0% 0 -3.0% -49,927 -3.0% -49,927 45-R5 23.3 99% 2% 33,285 0% 0 Timble Co 6 1663,435,446 0.0% 0 -3.0% -49,901 3.0% -49,901 45-R5 23.3 98% 2% 33,287 0% 0 Brown 5 2,265,166 40 0.0% 0 -3.0% -48,773 -3.6% -48,773 3,587 23.3 98% 2% 75,709 0% 0 Brown 6 1.354,816.11 0.0% 0 -3.6% -48,773 -3.5% -48,773 45-R5 23.3 98% 2% 75,709 0% 0 Brown 6 1.354,816.11 0.0% 0 -3.6% -48,773 -3.5% -48,773 45-R5 23.3 98% 2% 75,709 0% 0 Brown 6 1.354,816.11 0.0% 0 -3.6% -48,773 -3.5% -48,773	Prandovs kun GT 13 2.456,320.01 0.0% 0 -1.6% -39,301 1.5.Ks -33,301 45-R5 2.3.3 98% 2% 49,126 0% 0 Timble Co 5 1.664,234.64 0.0% 0 -3.0% -49,927 -3.0% -49,927 45-R5 23.3 98% 2% 49,126 0% 0 Timble Co 6 1.664,234.64 0.0% 0 -3.0% -49,927 -3.0% 49,927 45-R5 23.3 98% 2% 33,285 0% 0 Timble Co 6 1.664,551.66 0.0% 0 -3.0% -49,901 45-R5 23.3 98% 2% 33,287 0% 0 Brown 5 2.565.166 0.0% 0 -1.2% -27,182 45-R5 23.3 98% 2% 45,303 0% 0 Brown 6 1.364,816.11 0.0% 0 -3.6% -48,773 -3.5% 48,773 45-R5 23.3 98% 2% 2% 0		-	Accessory Electric Equipment															
Timple Co 3 1,664,234.64 0.0% 0 -3.0% -49.927 -3.0% -49.927 -3.0% -49.20 -2.3.3 90% 2% -49.126 0% 0 Timble Co 6 1,663,355.15 0.0% 0 -3.0% -49.901 -3.0% -49.901 -3.0% -49.901 -3.0% -3.2% -49.307 0% 0 Brown 5 2.265,166.84 0.0% 0 -1.2% -27,182 -1.2% -27,182 45-R5 2.3.3 98% 2% -33,287 0% 0 Brown 6 1.354,816.11 0.0% 0 -3.6% -48,773 -3.6% -48,773 45-R5 2.3.3 98% 2% -7, 766 0% 0	Timple Co 3 1,664,234,64 0.0% 0 .3.0% 49,927 -3.0% 49,927 45-R5 2.3.3 98% 2% 94,126 0% 0 Timple Co 6 1,663,336,15 0.0% 0 -3.0% 49,901 -3.0% 49,901 45-R5 2.3.3 98% 2% 33,285 0% 0 Brown 5 2,265,166 40 0.0% 0 -1.2% -27,182 -1.2% -27,182 45-R5 2.3.3 98% 2% 45,303 0% 0 Brown 6 1,354,816,11 0.0% 0 -3.6% 48,773 -3.5% 48,773 45-R5 2.3.3 98% 2% 25, 7096 0% 0			Paddy's Run GT 13	2,456,320.01	0.0%	0	-1.6%	-39.301	-1.6%		45.05	0 00	7000	200				
Timese 1,663,365,15 0.0% 0 -3.0% -49,901 -3.0% -49,901 -3.0% -49,901 45-R5 2.33 98% 2% 33,265 0% 0 Brown 5 2,265,166.84 0.0% 0 -1.2% -27,182 -1.2% -27,182 45-R5 2.33 98% 2% 45,303 0% 0 1.354,816.11 0.0% 0 -3.6% -48,773 -3.6% -48,773 45-R5 2.33 98% 2% 75% 766 0% 0	Hume C 1.654.365.15 0.0% 0 -3.0% -49.901 -3.0% -49.901 -3.0% -49.901 -3.0% -2% -2% -3.267 0% 0 Hume C 2% -27.182 -1.2% -27.182 45-R5 2.3.3 98% 2% 33.267 0% 0 Brown 5 1.354.816.11 0.0% 0 -1.2% -48.773 -3.6% -48.773 45-R5 2.3.3 98% 2% 2% 37.096 0% 0			I mobie Co 5 Trimble Co 6	1,664,234.64	0.0%	0	-3.0%	-49,927	-3.0%		45-R5	5.52	%96 7880	% 2 N	49,126 33,265	%0	0	0.0%
Brown 6 27,182 -1,2% -27,182 -1,2% -27,182 45-R5 23.3 98% 2% 45,303 0% 0 1.354,816.11 0.0% 0 -3.6% -48,773 -3.6% -48,773 45-R5 23.3 98% 2% 75,706 nw 0	Brown 6 27,182 45,R5 23,3 98% 2% 45,303 0% 0 -1,2% -27,182 45,R5 23,3 98% 2% 45,303 0% 0 -3.6% -48,773 -3.6% -48,773 45,R5 23,3 98% 2% 27,096 0% 0			Brown 5	1,663,365.15	0.0%	0	-3.0%	-49,901	-3.0%		45-R5	23.3	% D6	870	007.00 22.267	å 8	0 1	0.0%
				Brown 6	2,265,166.84	0.0%	0	-1.2%	-27,182	-1.2%		45-R5	23.3	%86	۶×	33,207 45 303	%) 0	00	0.0%
					1,304,610.11	0.0%	0	-3.6%	-48,773	-3.6%		45-R5	23.3	%86 %86	22	200,01	% ð	- 0	0.0%

Table 2-a

Exhibit___(LK-3) Page 4 of 5

Centucky Util Electric Divis

Summary of Original Cost of Utility Plant in Service and Interim and Terminal Net Salvage

	% চন্দ্	****	٩	*******
	Interim Re % Of Tota // Cota // Cota // Cota // Cota	%0.0 %0.0 %0.0	0	%0.0 %0.0 %0.0 %0.0 %0.0 %0.0 %0.0 %0.0
	Factored Amount (9)		>	******
	Interim Retired (p) 0%	5 8 8 8 8 5 6 6 6 6	2	%0000000000000000000000000000000000000
nterim Retirement Rate Calculation	Interim Retired Amount (o)	36,088 36,088 18,327 19,424	Ī	512,089 980,027 84,62 7,415 7,415 137,320 357,320 113,516 96,282 16,828
rement Rat	Eerceut Setirement (n) 2%	~ ~ ~ ~ ~ ~ ~ ~ ~ ~ ~ ~ ~ ~		47% 47% 47% 47% 47% 47%
nterim Reti	m .	%86 %86 %86		53% 53% 53% 53% 53%
-	Avg Age At Ret. (Yns) () 23.3 23.3 23.3	23.3 23.3 23.3 23.3 23.3		120 120 120 120 120 120 120 120
	Interim Ret ASL/Curve (*) 45-R5	45-R5 45-R5 45-R5 45-R5		88.98 19.98
	Intr Total Net Salvage E <u>A</u> Amount AS/U (i) (j) -3.6% -59.303 45-R!	-58,071 -57,741 -58,645 -29,197	-526,559	-5,448 4,170 5,342 6,342 8,5,42 9,52 9,363 4,797 4,797 4,010
			-2.8%	-0.5% -0.2% -3.5% -3.3% -3.3% -3.3% -3.3% -1.1%
	Livel Salvage L Salvage Amount (h) -48,517 -59,303	-58,071 -57,741 -58,645 -29,197	-526,559	-5,448 -6,697 -6,697 -6,697 -6,342 -8,053 -8,053 -7,970 -7,989 -7,989 -7,010 -59,043
imate d'Este	Terminal Net Salve Terminal Net Salve - Arrount (9) -3.6% -48,51 -3.3% -59,30	-1.8% -3.2% 4.7%	-2.8%	-0.5% -0.2% -0.2% -0.2% -0.2% -1.1% -1.1% -1.1% -1.2%
ů	Mat Salvage % Amount (e) (f) 0.0% 0 0.0% 0	0000	o	000000000000000000000000000000000000000
	Interim Ne (e) 0.0%	%0.0 %0.0 0.0%	0.0%	0.0% 0.0% 0.0% 0.0% 0.0% 0.0% 0.0% 0.0%
Original	Cost 12/31/02 (d) 1,347,700.35 1,797,053.82	5,220,105.20 1,804,419.47 916,326.28 621,206.80	19,116,795.73	1,089,560,03 2,085,163,17 15,076,54 15,776,54 230,068,72 230,068,72 241,523,31 241,523,31 244,581,000,69 4,681,000,69
	Description	Brown 10 Brown 11 Hafeling	Total Account 345	Miscellaneous Power Plant Equipment Paddy's Run GT 13 Brown 5 Brown 6 Brown 9 Brown 9 Brown 10 Brown 10 Brown 11 Hateling Total Account 346
	~		Tota	Miscellan 0432 Paddy's R 5635 Brown 5 5635 Brown 5 5637 Brown 7 5633 Brown 8 5640 Brown 10 5641 Brown 11 5696 Haifeling 5641 Acco
	Account Location Code (a)(b) 5637 5639 5639	មមស្		8 9 9 9 9 9 9 9 9 9 9 9 9 9 9 9 9 9 9 9

-15,110,543

4.2%

-3.8% -13,603,331

-1,507,212

-0.4%

362,234,009.71

Total Other Production Plant

Table 2-a

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								Fage	1015	
Table 2		Annual Deprecation Rate (1)	1.75% 3.18% 2.17%	2 52% 2.80%	0.00% 2.04% 1.53% 5.74% 4.13%	0.80% 1.53%		4 18% 4 00%	1.91% 2.61% 3.43%	2 14% 2 27% 7 57% 2 74%
		Annuat Depreciation Accrual (k)	2,701,903 69 32,596,687 78 4,151,337 62 1,322,461 72	521,636.42 41,294,027.43	0 00 10,151,26 124,612.69 20,071 18 6,733 36	302.88 161,942.99	2.898 14 2.898 14 919.064 64 825.871.27 10.219.345 34 10.2696.546 34 642,365 93	195,752.02 14,502,743 65	438,860,47 167,840,76 40,004,24 207,844,00	3.330,714 05 1.080,987,88 4.411,701 93
		Average Remaining Life (J	211 19.6 201 22.9	20.6	7.8 16.9 14.5 3.1	15.6	23 6 24 9 25 5 25 5 25 5	21 4	22.9 28.0 19.1	34 0 7 1
		A.S.L./ Survivor Curve ()		(1) 60-51		CX-00	· · · •	20-61	50-R2.5 45-R3 40-R3	50-R2.5 15-R3
	of Itlan of 31, 2002	Net Originat Cost Less Salvage (h)		820,377,222.28	0.00 171,556.26 (1) 2,230,567,22 (1) -121,68 (1) 62,220.67 (1) 56,580.27 (1)		127,228,19 20,055,228,23 (1) 18,664,690.76 (1) 226,869,465 59 (1) 40,717,112,26 (1) 16,390,331,30 (1)	327,003,150,65	10,049,504,75 4,699,541.25 764,080.90 5,463,622.15	113,244,277.77 7,675,013.96 120,919,291.73
	e and Calculation Based Upon Utiliza Is as of December	Book Depreciation <u>Reserve</u> (g)	119,979,591,98 478,215,496,00 127,644,966,20 58,664,298,73	794,854,592.77	879,311,47 397,997,88 5,927,893,37 652,592,49 315,637,69 108,299,12 108,299,12 42,173 07	8,323,904.23	49,181,12 3,086,998,33 3,253,075,18 3,253,075,18 28,681,301,92 11,415,853,11 11,415,853,11 3,271,734,71 5,57,734,71	50,312,904.75 12,944.75	3,333,642,20 693,961,91 4,027,604,11	55,262,160 21 8,038,391.66 63,300,551.87
Kentucky Utlities Electric Division	Summary of Orighal Cost of Utility Plant in Service and Calculation of Annual Deprectation Rates and Depreciation Expense Based Upon Utilization of 300k Deprecation Reserve and Average Remaining Lives as of December 31, 2002	Original Cost Less Salvage (I)	176,989,764,06 1,117,110,576,45 211,086,852,41 88,849,002,12 21,195,620,01	1,615,231,815.05	879,311,47 569,554,14 8,158,460,59 652,470,81 377,885,56 166,878,39 48,145,91	10,852,679.87	176,409,31 23,144,227,56 21,917,765,94 255,550,767,51 52,132,966,01 19,655,37 19,655,37 4,741,853,70	377,316,055,40 22,991,433,46	8,033,183,45 1,458,042.81 9,491,226,26	168,506,437.98 15.713,405.62 184,219,843.60
Kentu Elec	f Original Cost of U tion Rates and Dep Reserve and Aver	Sstimated Future <u>Net Salvaoe</u> Amount (e)	-22,278,431,84 -92,238,487,96 -19,364,007,35 -7,559,807,65 -476,538,87	-141,917,353.67	0.00 -72,126.94 -16,284.35 -119,884.58 -27,9884.58 -3,751.91 -3,751.90	-239,994.30	0.00 -1,969,270.96 -3,591,874,69 -4,271,743,41 -4,653,033,34 -535,270,28 -535,270,28	-15,082,045.69 0.00	-1,606,636,69 -291,608.56 -1,898,245.25	-21,979,100.61 -1,428,481.42 -23,407,592.03
	Summary ol ial Deprecia Deprecation		-14.4% -9.0% -10.1% -9.3%	%9 [.] 6-	0.0% -14.5% -0.2% -22.5% -2.3% 0.0%	-2.3%	0.0% -9.3% -1.7% -2.8% -1.3%	4.2% 0%	-25% -25% -25.0%	-15% -10% -14.6%
	Sum Annual Da Book Depr	Original Cost 12/31/02 (c)	154,711,332,22 1,024,872,088,49 191,722,845,06 81,289,114,47 20,719,081,14	1,473,314,461.38	879,311.47 497,427,20 8,142,176,24 532,629,23 349,869,04 163,126,48 163,126,48	10,612,685.57	176,409.31 21,174,956.60 18,325,891.25 251,279,024.10 47,479,932.03 19,116,795,73 19,116,795,73 4,681,000.69	362,234,009.71 22,991,433.46	6,426,546.76 1,166,434.25 7,592,981.01	146,527,337,37 14,284,914,20 160,812,251,57
		bunt <u>Description</u> (b) <u>DEPRECIABLE PLANT</u>	STEAM PLANT OB Structures and Improvements 00 Boiler Plant Equipment 00 Turbogenerator Units 00 Accessory Electric Equipment 00 Miscellaneous Power Plant Equipment		Land Rights Structures an Reservoirs, D Watenwheel, Accessory Ete Miscellaneous Roads, Raitro		 Land Rights Structures and Improvements Fuel Holders, Producers and Accessory Prime Movers Permerators Generators Accessory Electric Equipment Miscellaneous Power Plant Equipment 	Total Other Production Plant TRANSMISSION PLANT 350.10 Land Rights	Struct. and Im Struct. and Im Struct and Im Total Accou	Station Equipment Station Equipment - Non Sys. Control/Com. Station Equip - Sys Control/Com (Microwave) Total Account 353
		Account <u>No.</u> (a)	311.00 312.00 314.00 315.00 316.00	:	330,10 331,00 333,00 334,00 334,00 335,00		341.10 341.00 343.00 345.00 345.00 345.00 345.00	350.10	352.10 352.20	353.10 353.20

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	Annual Deprecation Rate	≘	287%	3 72%	2.04%	4.24%	3.08%		161%	2.12%	364%	3 24%	2 05%	3.41%	4.40% 4.18%	2 20%	6.05% 3.75%		311%	1.74% 2.39%	1 76%	5.61%	4.88% 5.57%	2.14%	2.63%	2.30%
	Annual Depreciation De Accrual	1 	1,736,947.60	2,789,736.88 4 217 252 85	8,878.46	47,229.16	13,858,452,36		22,941.95	00,043.77	6.091,261.52	5,204,138.72	31,823 02 1 505 355 50	1,030,300.09 5,157,350,17	3,396,791,58	1,344,977,65	1,104,689,49 1 703 095 99		21.125,964,83	504,884.51 16,632.32	521,526 83	346,235,43	18,033.02 364,268 46	12,232.43	97,328 06 87 210 43	
	Average Remaining Life	Э	33.2	28.0 29.9	39.2	15.4		č	299 A	37.9	29.9	28.2	28 8 23 0	30.8	18.9	32.2	20.9 20.9		•	38.3 12.1		11.5 2.1	9	17 9	21.9 17.5	92
	A.S.L./ Survivor Curve	8	55-R4	50-R3	50-R3	52-05		50 D3 6	50-R2 5	50-R1.5	40-S0	41-R2	30-R3	42-S0.5	30-R3	44-R1	28-R1			50-R1.5 20-R1		15-L1	+X-71	30-R3	30-R2.5 27-L3	18-S5
t on of 1, 2002	Net Original Cost Less Salvage	Ē	57,666,660.40 78 112 632 60	126,095,860.54	348,035.46 727 320 02	20.620, 121	0/ Off foot een	502 428 79	2,931,793.20	72,994,037.95	182,128,719.41 145 755 744 00	0 1 1 0 0 1 1 7 0 0 1 1 7 0 0 1 0 0 0 0	40,543,646.79	158,846,385,27	64, 199, 360.85	43,308,280.46 11 820.177 53	35,594,706.20	760.542.751 44		19,337,459,70 201,251,09	6/ 10 / 920' 11	3.981,707 48	4 100,725 43	218,960.43	2, 131,484,59 1,526,339,98	44,138.81
Summary of Original Cost of Utility Plant in Service and Calculation of Annual Depreciation Rates and Depreciation Expense Based Upon Utilization of Book Deprecation Reserve and Average Remaining Lives as of December 31, 2002	Book Depreciation Reserve	(2)	39,186,874.18 41,752,871,90	87,456,803.12	87,891.34 610.385.26	249.364.510.47		920,753,34	1,436,285.62	28,771,438,30	85 985 153 79	790 660 29	11,750,621.73	71,829,368.57	50,153,941.91	7.363.640.96	14,352,579.64	368,766,227.04		11,099,276.95 493,238.08	50.010'300'L	2,186,764.50 250.365.99	2,437,130,49	352,897.62 1 550 235 34	1,780,545.79	126,436.76
lifty Plant in Service eciation Expense B ge Remaining Lives	Onginal Cost Less Salvage (1)		90,853,534.58 119,865,504.59	213,552,663.66 425,000,000	4.35,926.80 1,337,714.28	648,747,847,23		1,423,182.13	4,368,078.82	101,765,476.25 259 715 747 26	232,741,865,72	1,707,163.36	52,294,268.52	230.675,753.84	61.133,302.76	19,183,818.49	49,947,265.84	1,129,308,978.48		30,436,736,65 694,489,17 31 131 725,82		6, 168, 471.98 369,383.94	6,537,855.92	571,858.05 3.700.720.83	3,306,885.77	10.010,011
Original Cost of Ul ion Rates and Depr Reserve and Avera	Estimated Future <u>Net Salvage</u> Amount (e)	57 JC6 96-	44,949,564,22	-91,522,570,14 0.00	-222,952.38	-196,320,999.49		0.00	-569,749.41 -0.251.405.02	-92,157,200.64	-72,230,234.19	-155,196.67	-2,490,203.26	-20,570,025,00	00.0	-913,515.17	-4,540,662.35	-235,951,063.92		-1,449,368,41 0.00 -1,449,368,41		0.00	0.00	00.0	0.00 30 101 57	
Summary of al Depreciati Jeprecation	Estim (d)	-60%	%09	%ç/-	-20%	-44.0%		0% 20%	-10% -10%	-55%	45%	-10%	-5%	40%	%0	-5%	-10%	-28.4%		5% 9% 4		%0 %0	%0'0	%0 0	0% 15%	
Annu Book [Original Cost 12/31/02 (c)	60,533,459,11	74,915,940.37	435,926.80	1,114,761.90	450,426,847.74		1,423,182.13 3 708 320 41	92,514,069,32	167,558,546.62	160,511,631,53	1,551,966.69	43,004,003.26 209.705.230.76	81,680,930.54	61, 133, 035, 49	18,270,303.32 45,400,533,40	84'070'00 4' 84	893,357,914.56		28,997,368,24 694,489,17 29,681,857,41		6,168,471.98 369,383.94 6 537 855 55	78'000'100'0	571,858.05 3,700,720.83	3,306,885.77 200,677,14	
	<u>Description</u> (b)	Towers and Fixtures	Poies and Fixtures Overhead Conductors and Devices	Underground Conduit	Underground Conductors and Devices	Total Transmission Plant	DISTRIBUTION PLANT	Land Rights Structures and Improvements	Station Equipment	Poles, Towers and Fixtures	Underground Conduit	Underground Conductors and Devices	Line Transformers	Services	Meters Installations on Custommer Development	Street Lighting and Signal Systems		l otal Distribution Plant	GENERAL PLANT	Structures and Improvements 390.10 Struct. And Improve. To Owned Property 390.20 Improvements to Leased Property Total Account 390	Office Furniture and Equipment	Office Equipment Cash Processing Equipment Total Account 391	Stores Equinment	Tools, Shop and Garage Equipment	Power Operated Equipment	
	Account <u>No.</u> (a)	354.00 T		357.00 U		F				20 4 00 4 00 00 4 00 00 4 00		367.00 Un	_	369.00 Se			F	ġ		390.10 Sln 390.20 Imp		391.10 Officers 391.30 Cas	393.00 Stor			

Table 2

Exhibit___(LK-4) Page 2 of 3

		Su Annual Book De	mmary of (Depreciation precation F	Driginal Cost of Util on Rates and Depre Reserve and Averaç	Summary of Original Cost of Utility Plant in Service and Calculation of Annual Depreciation Rates and Depreciation Expense Based Upon Utilization of Book Deprecation Reserve and Average Remaining Lives as of December 31, 2002	and Calculation o ised Upon Utilizati as of December 3	r on of 1, 2002				
Account No. Desc (a) (<u>Description</u> (b)	Original Cost 12/31/02 (c)	Estim: Net (d)	Estimated Future <u>Net Salvage</u> Amount. (e)	Original Cost Less Salvage (1)	Book Depreciation <u>Reserve</u> (9)	Nel Original Cost Less Salvage (h)	A.S.L./ Survivor Curve	Average Remaining Life	Annual Depreciation Accrual	Annual Deprecation Rate
Communication Equipment 397.10 Carrier Communication Equipment 397.20 Remote Communication Equipment 397.30 Mobile Communication Equipment Total Account 397	Communication Equipment mmunication Equipment antrol Communication Equipment mmunication Equipment count 397	3,093,194.70 3,889,910.58 4,579,895.62 11,563,000.90	%0 %0 0	00.0 00.0 00.0	3,093,194.70 3,889,910.58 4,579,895.62 11,563,000.90	1,426,603.39 1,309,606.44 1,190,962.85 3,977,767.68	1,666,501.31 2,580,304.14 3,388,932.77 7,536.77	19-S6 20-L5 18-S5	13 8 15 8 15 1	120,760.96 163,310.39 224,432.63	4 4 3 3 9 9 9 8 9 9 8 8
398.00 Miscellaneous Equipment	F	457,348.94	10%	45,734.89	411,614.05	224,361.12	r,uuu,r.30.22 187.252.93	19-115	176	508,503.99	4.40%
Total General Plant		56,020,204.96	-2.5%	-1,373,531.95	57,393,736.91	22,010,385.72	35,383,351,19		C71	14,960 23	3.28%
Sub-Total Depreciable Plant	lant	3,245,966,123.92	-18.3%	-592,884,989.02	3,838,851,112,94 1,493,632,524,98	,493,632,524.98	2,345,218,587.96			21.700,010,1 99,187,988,37	2.88% 3.06%
Other Plant (Not Sludied) 391.20 Non PC Computer Equipment 391.40 Personal Computers 392.00 Transportation Equipment - Cars & Trucks	Vot Studied) ment it - Cars & Trucks	9,611,731,44 9,814,322,00 23,749,238.51				3,963,686.38 8,735,674.86 14,621,439.53					
Total Other Plant (Not Studied)	t (Not Studied)	43,175,291.95				77 008 005 70					
Total Depreciable Plant		3,289,141,415.87			-	1,520,953,325.75					
NON-DEPRECIABLE PLANT	ABLE PLANT										
INTANGIBLE PLANT 301.00 Organization 302.00 Franchises and Consents 303.00 Miscellaneous Intangible Plant	E PLANT Plant	44,455.58 81,350.32 17,297,387.08				0.00 80.321.44 18.192.711.00					
Total Intangible Plant		17,423,192.98				18,258,032,44					
LAND & LAND RIGHTS 310.20 Production Land 330.20 Hydraulic Plant 340.20 Other Production Land 350.20 Transmission Land 360.10 Distribution Land 389.20 Land) RIGHTS	10,478,524,55 13,478,47 98,802.74 1,162,528.04 1,584,825,82 2,826,347,43				0.00 0.00 -8,503.92 -8,503.92					
Total Land		16,164,308.05				145.679.08					
Total Non-Depreciable Plant	ant	33,587,501.03				18,403,711.52					
Total Electric Plant in Service	vice	3,322,728,916.90			1,5	1,539,357,037.27					
(1) Life Span Method Utitzed Interim Retirement $\alpha_{min} = \alpha_{m}$	d Interim Retirement 6	Onto Control 1 14.									

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

Table 2

Kentucky Utilities Electric Division

Exhibit___(LK-4) Page 3 of 3

Kentucky Utilities Company Annualized Depreciation at September 30, 2003 Using Historical Gross Salvage and Cost of Removal

	Depreciable Balance 09/30/03	_	Current Rates Implemented 1-Jan-01	Proposed Rates KIUC	Depreciation Under Current Rates	Depreciation Under Adjusted Rates	Net Difference Current/Adjusted Rates
ntangible Plant							
301 Organization	44,456	ND	0.00%	0.000/			
302 Franchises and Consents	83,453		0.00%	0.00% 0.00%	-	-	-
303 Misc. Intangible Plant	21,631,290		20.00%	20.00%	4,326,258	- 4,326,258	-
otal Intangible Plant	21,759,199			20.0070	4,326,258	4,326,258	
Steam Production Plant							
Land	10,475,562	ND		0.00%		_	_
Brown Unit 1	45,247,316	i	2.90%	2.30%	1,312,172	1,040,688	(271,484)
Brown Unit 2	38,238,854		2.88%	2.76%	1,101,279	1,055,392	(45,887)
Brown Unit 3	116,091,020		3.91%	2.61%	4,539,159	3,029,976	(1,509,183)
Ghent Unit 1	138,894,035		3.12%	3.64%	4,333,494	5,055,743	722,249
Ghent Unit 2 Ghent Unit 3	144,169,095		1.84%	1.98%	2,652,711	2,854,548	201,837
Ghent Unit 4	276,892,827		2.22%	2.43%	6,147,021	6,728,496	581,475
Green River Units 1&2	271,961,803 20,081,091		2.16%	2.51%	5,874,375	6,826,241	951,866
Green River Units 3	16,872,163		0.00% 1.94%	0.00%	•		•
Green River Units 4	35,240,942		3.10%	1.12% 1.77%	327,320	188,968	(138,352)
Pineyville	226,833		2.28%	0.00%	1,092,469 5,172	623,765	(468,705)
Tyrone Units 1&2	6,639,170		0.00%	1.13%	5,172	-	(5,172)
Tyrone Unit 3	18,792,326		2.13%	0.82%	400,277	75,023 154,097	75,023
System Laboratory				0.0270	400,277	104,087	(246,179)
1311	805,716		4.22%	1.95%	34,001	- 15,711	(18,290)
1316	1,965,213		4.22%	2.94%	82,932	57,777	(16,250)
Coal Cars	7,647,232	NG	4.59%	1.96%	351,008	149,886	(201,122)
Pollution Control Equipment	<u>114,781,009</u>		5.67%	4.08%	6,508,083	4,683,065	(1,825,018)
Total Steam Production Plant	1,265,022,207				34,761,473	32,539,376	(2,222,096)
lydraulic Production Plant							
Land	13,479	ND	0.00%	0.00%	-	-	
Dix Dam Lock # 7	9,914,306		1.59%	1.16%	157,63 7	115,006	(42,632)
fotal Hydraulic Production Plant	840,028 10,767,813		2.46%	5.84%	20,665	49,058	28,393
Other Bradewith Black	,,				178,302	164,064	(14,239)
Other Production Plant Land							
Haefling	98,603	ND	0.00%	0.00%	-	-	-
Brown CT 5	5,296,000		0.00%	3.36%	-	177,946	177,946
Brown CT 6	20,296,408 36,701,293		3.43%	2.97%	696,167	602,803	(93,363)
Brown CT 7	38,256,129		3.39%	2.95%	1,244,174	1,082,688	(161,486)
Brown CT 8	27,638,671		3.28% 3.51%	2.88%	1,254,801	1,101,777	(153,025)
Brown CT 9	36,697,794		3.39%	2.40%	970,117	663,328	(306,789)
Brown CT 10	27,720,786		3.48%	2.79% 2.90%	1,244,055	1,023,868	(220,187)
Brown CT 11	42,757,087		3.55%	3.06%	964,683 1,517,877	803,903	(160,781)
Brown CT Gas Pipeline	8,364,109		3.39%	3.43%	283,543	1,308,367	(209,510)
Paddy's Run Generator 13	29,973,105		3.43%	3.01%	1,028,078	286,889	3,346 (125,887)
Trimble County CT 5	39,045,125		3.43%	3.00%	1,339,248	902,190 1,171,354	(125,887)
Trimble County CT 6	39,024,692		3.43%	3.00%	1,338,547	1,170,741	(167,894) (167,806)
Trimble County CT Pipeline	4,474,853	-	3.43%	3.51%	153,487	157,067	3,580
Fotal Other Production Plant	356,344,656				12,034,777	10,452,921	(1,581,856)
Transmission Plant							• •
350.1 Land Rights	23,341,271		1.34%	2.44%	312,773	569,527	256,754
350.2 Land	1,162,528	ND				-	200,704
352 Structures & Improvements	7,758,006		2.65%	7.41%	205,587	574,868	369,281
353.1 Station Equipment	154,930,533		2.21%	0.69%	3,423,965	1,069,021	(2,354,944)
353.2 Syst Control/Microwave EquipStation Equi 354 Towers & Fixtures	14,789,869		6.18%	6.20%	914,014	916,972	2,958
355 Poles & Fixtures	62,743,597		2.84%	2.44%	1,781,918	1,530,944	(250,974)
356 Overhead Conductors & Devices	80,841,658 125,832,855		4.03%	3.73%	3,257,919	3,015,394	(242,525)
357 Undergound Conduit	448,760		3.25%	0.00%	4,089,568	-	(4,089,568)
358 Underground Conductors & Devices	1,114,762		2.01% 3.52%	2.04% 2.94%	9,020	9,155	135
359 Transmission ARO's [otal Transmission Plant	0		0.0270	2.94%	39,240	32,774	(6,466)
	472,963,839				14,034,003	7,718,654	(6,315,349)
Distribution Plant							
360.1 Land Rights 360.2 Land	1,423,182		1.14%	0.62%	16,224	8,824	(7,401)
361 Structures and Improvements		ND	0.00%	0.00%	-	-	
	4,126,448		1.89%	1.84%	77,990	75,927	(2,063)

Kentucky Utilities Company Annualized Depreciation at September 30, 2003 Using Historical Gross Salvage and Cost of Removal

	Depreciable Balance 09/30/03	-	Current Rates Implemented 1-Jan-01	Proposed Rates KIUC	Depreciation Under Current Rates	Depreciation Under Adjusted Rates	Net Difference Current/Adjusted Rates
362 Station Equipment	96,700,056		2.24%	0,89%	2,166,081	860,630	(4.005.454)
364 Poles Towers & Fixtures	176,881,754		3.52%	1.46%	6,226,238	2,582,474	(1,305,451) (3,643,764)
365 Overhead Conductors & Devices	165,135,703		3.02%	1.70%	4,987,098	2,807,307	(2,179,791)
366 Underground Conduit	1,664,173		1.75%	1.93%	29,123	32,119	2,996
367 Underground Conductors & Devices	56,772,724		3,29%	0.50%	1,867,823	283,864	(1,583,959)
368 Line Transformers	219,930,197		2.41%	2.27%	5,300,318	4,992,415	(1,363,939) (307,902)
369 Services	82,837,019		3.75%	3.75%	3,106,388	3,106,388	(307,902)
370 Meters	62,508,577		2.79%	2.13%	1,743,989	1,331,433	(412,557)
371 Installations on Customer Premises	18,268,926		6.27%	6.41%	1,145,462	1,171,038	25,576
373 Street Lighting & Signal Systems	50,814,837		3.85%	2.39%	1,956,371	1,214,475	(741,897)
otal Distribution Plant	938,776,962	•			28,623,105	18,466,893	(10,156,212)
General Plant							(//////////////////////////////////////
389.2 Land	2.825.417	ND	0.000				1
390.1 Structures & Improvements	,,	ND	0.00%	0.00%	-	-	-
390.2 Improvements to Leased Property	30,511,481		1.76%	0.24%	537,002	73,228	(463,775)
391.1 Office Furniture & Equipment	756,079		0.00%	2.40%	-	18,146	18,146
391.2 Non PC Computer Equipment	6,631,398		5.82%	5.50%	385,947	364,727	(21,220)
391.3 Cash Processing Equipment	13,732,616		20.00%	20.00%	2,746,523	2,746,523	-
391.4 Personal Computer Equipment	817,575		10.00%	4.88%	81,758	39,898	(41,860)
392 Transportation Equipment	11,716,009		33.33%	33.33%	3,904,946	3,904,946	-
393 Stores Equipment	23,749,239		20.00%	20.00%	4,749,848	4,749,848	•
394 Tool, Shop, and Garage Equipment	674,815		2.87%	2.14%	19,367	14,441	(4,926)
395 Laboratory Equipment	4,637,322		2.74%	1.46%	127,063	67,705	(59,358)
396 Power Operated Equipment	3,307,714		3.16%	1.96%	104,524	64,831	(39,693)
397 Communication Equipment	225,500		3.56%	4.02%	8,028	9,065	1,037
398 Misc Equipment	13,113,712		3.55%	4.40%	465,537	577,003	111,467
Total General Plant	<u>463,335</u> 113,162,212		5.19%	0.00%	24,047		(24,047)
	110,102,212				13,154,589	12,630,360	(524,229)
[OTAL PLANT excluding ARO Assets	3,178,796,889						4 Ç
ARO Assets excluded from Plant in service	8,608,030						
⊺otal Plant in Service	3,187,404,919						
Total Annual Depreciation					107,112,508	86,298,526	(20,813,981)
Less Amounts not included in Income State	ement Depreciation						
Coal Cars					351,008	150 400	(100 000)
Brown Gas Pipeline					283,543	152,180	(198,828)
TC Gas Pipeline					203,543 153,487	376,385	92,842
Account 139200 Transportation Equipment					4,749,848	192,419	38,932
Subtotal				-	5,537,886	<u>4,749,848</u> 5,470,832	(67,054)
Less ECR Depreciation						. ,	(07,004)
					194,434	223,677	29,243
Total Annualized Depreciation				-	101,380,187	80,604,017	(20,776,170)

Kentucky Utilities Company Annualized Depreciation at September 30, 2003 Using Historical Gross Salvage and Cost of Removal

	Depreciable Balance 09/30/03	Current Rates Implemented 1-Jan-01	Proposed Rates KIUC	Depreciation Under Current Rates	Depreciation Under Adjusted Rates	Net Difference Current/Adjusted Rates
Forma Depreclation Adjustment						
Twelve months ended 9/30/03 per books						
Depreciation						96,724,719
Amortization						4,509,128
Less:Depreciation SFAS 143 Assets						(131,239)
Less:Depreciation of ECR Assets						(194,436)
						100,908,171
Annualized Depreciation under current rates						101,380,187
(1) Adjustment due to annualizing current rates						472,016
12 months depreciation under KIUC rates for ac						80,604,017
Less:Annualized Depreciation under current rat	es					(101,380,187)
(2) Adjustment due to proposed rates						(20,776,170)
Total Adjustment (1) + (2)						(20,304,154)
						int.
KU Proposed Adjustment						. 2,395,535
Total Net Difference Between KIUC Adjustment for	Gross SaluiCOP					1 and
and KU Proposed Adjustment						(22,699,689)
Kentucky Jurisdiction Percentage						87.299%
Kentucky Jurisdiction Amount						

Kentucky Utilities Company Annualized Depreciation at September 30, 2003 Using Historical Gross Salvage and Cost of Removal and Removing Interim Additions for NOX Compliance

	Depreciable Balance 09/30/03	_	KIUC Rates W/Adjust. Gross Salv/COR	Proposed Rates KIUC	Depreciation Under KIUC Rates W/Adjust. Gross Salv/COR	Depreclation Under KIUC Rates	Net Difference KIUC Rates W/Adjust. Gross Salv/COR/ KIUC Rates
ntangible Plant							
301 Organization	44,456	ND	0.00%	0.00%	_		
302 Franchises and Consents	83,453		0.00%	0.00%	-	-	-
303 Misc. Intangible Plant	21,631,290			20.00%	4,326,258	4,326,258	-
otal Intangible Plant	21,759,199				4,326,258	4,326,258	
Steam Production Plant							
Land	10,475,562	ND		0.00%	-	_	_
Brown Unit 1	45,247,316		2.90%	2.21%	1,312,172	999,966	(312,206)
Brown Unit 2	38,238,854		2.88%	2.45%	1,101,279	936,852	(164,427)
Brown Unit 3	116,091,020		3.91%	2.35%	4,539,159	2,728,139	(1,811,020)
Ghent Unit 1	138,894,035		3.12%	2.00%	4,333,494	2,777,881	(1,555,613)
Ghent Unit 2	144,169,095		1.84%	1.86%	2,652,711	2,681,545	28,834
Ghent Unit 3	276,892,827		2.22%	1.78%	6,147,021	4,928,692	
Ghent Unit 4	271,961,803		2.16%	2.04%	5,874,375	5,548,021	(1,218,328)
Green River Units 1&2	20,081,091		0.00%	0.00%	0,074,010	5,546,021	(326,354)
Green River Units 3	16,872,163		1.94%	0.41%	327,320	69,176	-
Green River Units 4	35,240,942		3.10%	1.73%	1,092,469	,	(258,144)
Pineyville	226,833		2.28%	0.00%		609,668	(482,801)
Tyrone Units 1&2	6,639,170		0.00%	1.08%	5,172		(5,172)
Tyrone Unit 3	18,792,326		2.13%	0.26%	-	71,703	71,703
System Laboratory	10,102,020		2.1370	0.20%	400,277	48,860	(351,416)
1311	805,716		4.22%	1 059/	-	-	
1316	1,965,213		4.22%	1.95%	34,001	15,711	(18,290)
Coal Cars	7,647,232	NG	4.22%	2.94%	82,932	57,777	(25,155)
Pollution Control Equipment	114,781,009	NG		1.90%	351,008	145,297	(205,711)
otal Steam Production Plant	1,265,022,207	•	5.67%	3.98%	<u>6,508,083</u> 34,761,473	4,568,284	(1,939,799) (8,573,900)
Hydraulic Production Plant					,,	20,101,010	(0,57 3,500)
Land	13 470	ND	0.000/				
Dix Dam	13,479	ND	0.00%	0.00%	-	-	-
Lock #7	9,914,306		1.59%	1.16%	157,637	115,006	(42,632)
Total Hydraulic Production Plant	840,028 10,767,813		2.46%	5.84%	20,665 178,302	49,058 164,064	28,393
Ther Production Direct	, ,				170,502	104,004	(14,239)
Other Production Plant Land	00.000		•				
Haefling	98,603	ND	0.00%	0.00%	-	-	•
Brown CT 5	5,296,000		0.00%		-	-	-
Brown CT 6	20,296,408		3.43%	2.97%	696,167	602,803	(93,363)
Brown CT 7	36,701,293		3.39%	2.95%	1,244,174	1,082,688	(161,486)
Brown CT B	38,256,129		3.28%	2.88%	1,254,801	1,101,777	(153,025)
	27,638,671		3.51%	2.40%	970,117	663,328	(306,789)
Brown CT 9	36,697,794		3.39%	2.79%	1,244,055	1,023,868	(220.187)
Brown CT 10	27,720,786		3.48%	2.90%	964,683	803,903	(160,781)
Brown CT 11	42,757,087		3.55%	3.06%	1,517,877	1,308,367	(209,510)
Brown CT Gas Pipeline	8,364,109		3.39%	3.43%	283,543	286,889	3,346
Paddy's Run Generator 13	29,973,105		3.43%	3.01%	1,028,078	902,190	(125,887)
Trimble County CT 5	39,045,125		3.43%	3.00%	1,339,248	1,171,354	(125,887)
Trimble County CT 6	39,024,692		3.43%	3.00%	1,338,547	1,170,741	(167,806)
Trimble County CT Pipeline fotal Other Production Plant	4,474,853	-	3.43%	3.51%	153,487	157,067	3,580
	356,344,656				12,034,777	10,274,975	(1,759,802)
Transmission Plant							-
350.1 Land Rights	23,341,271		1.34%	2.44%	312,773	500 507	
350.2 Land	1,162,528	ND		2.9470	512,115	569,527	256,754
352 Structures & Improvements	7,758,006		2.65%	7.41%	-	-	•
353.1 Station Equipment	154,930,533		2.21%	0.69%	205,587 3,423,965	574,868	369,281
353.2 Syst Control/Microwave EquipStation Equi	14,789,869		6.18%	6.20%		1,069,021	(2,354,944)
354 Towers & Fixtures	62,743,597		2.84%		914,014	916,972	2,958
355 Poles & Fixtures	80,841,658		4.03%	2.44% 3.73%	1,781,918	1,530,944	(250,974)
356 Overhead Conductors & Devices	125,832,855		3.25%	0.00%	3,257,919	3,015,394	(242,525)
357 Undergound Conduit	448,760		2.01%	2.04%	4,089,568	-	(4,089,568)
358 Underground Conductors & Devices	1,114,762				9,020	9,155	135
359 Transmission ARO's	0		3.52%	2.94%	39,240 -	32,774	(6,466)
Fotal Transmission Plant	472,963,839	-			14,034,003	7,718,654	(6,315,349)
Distribution Plant							•••••••
360.1 Land Rights	1,423,182		1.14%	0.62%	16 224	A 904	·=
360.2 Land		ND	0.00%	0.02%	16,224	8,824	_ (7,401)
	.,		0.00%	0.00%	-	-	-

Kentucky Utilities Company Annualized Depreciation at September 30, 2003

Using Historical Gross Salvage and Cost of Removal and Removing Interim Additions for NOX Compliance

361 Structures and Improvements 4,126,448 1.89% 1.84% 77,9 362 Station Equipment 96,700,056 2.24% 0.89% 2,166,0 364 Poles Towers & Fixtures 176,881,754 3.52% 1.46% 6,226,2 365 Overhead Conductors & Devices 165,135,703 3.02% 1.70% 4,987,0 366 Underground Conduit 1.664,173 1.75% 1.93% 29,1 367 Underground Conductors & Devices 56,772,724 3.29% 0.50% 1,867,8 368 Line Transformers 219,930,197 2.41% 2.27% 5,300,3 369 Services 82,837,019 3.75% 3.75% 3,106,3 370 Meters 62,508,577 2.79% 2.13% 1,743,9 371 Installations on Customer Premises 18,268,926 6.27% 6.41% 1,145,4 373 Street Lighting & Signal Systems 50,814,837 3.85% 2.39% 1,956,3 389.2 Land 2,825,417 ND 0.00% 0,00% 2.825,417	81 860,630 (1,305,38 38 2,582,474 (3,643,98 98 2,807,307 (2,179,23 23 32,119 2,23 23 283,864 (1,583,18 18 4,992,415 (307,88 88 3,106,388 (412,62) 62 1,171,038 25,36	,764) ,791) ,996 ,959) ,902) - 557)
362 Station Equipment 96,700,056 2.24% 0.89% 2,166,0 364 Poles Towers & Fixtures 176,881,754 3.52% 1.46% 6,226,2 365 Overhead Conductors & Devices 165,135,703 3.02% 1.70% 4,987,0 366 Underground Conduit 1,664,173 1.75% 1.93% 29,1 367 Underground Conductors & Devices 56,772,724 3.29% 0.50% 1,867,8 368 Line Transformers 219,930,197 2.41% 2.27% 5,300,3 369 Services 82,837,019 3.75% 3.75% 3,106,3 370 Meters 62,508,577 2.79% 2.13% 1,743,9 371 Installations on Customer Premises 18,268,926 6.27% 6.41% 1,145,4 373 Street Lighting & Signal Systems 50,814,837 3.85% 2.39% 1,956,33 3eneral Plant 938,776,962 28,623,10 28,623,10	81 860,630 (1,305,38 38 2,582,474 (3,643,98 98 2,807,307 (2,179,23 23 32,119 2,23 23 283,864 (1,583,18 18 4,992,415 (307,88 88 3,106,388 (412,62) 62 1,171,038 25,36	(451) (764) (791) (996) (959) (902) (- (557)
364 Poles Towers & Fixtures 176,881,754 3.52% 1.46% 6,226,2 365 Overhead Conductors & Devices 165,135,703 3.02% 1.70% 4,987,0 366 Underground Conduit 1,664,173 1.75% 1.93% 29,1 367 Underground Conductors & Devices 56,772,724 3.29% 0.50% 1,867,8 368 Line Transformers 219,930,197 2.41% 2.27% 5,300,3 369 Services 82,837,019 3.75% 3.75% 3,106,3 370 Meters 62,508,577 2.79% 2.13% 1,743,9 371 Installations on Customer Premises 18,268,926 6.27% 6.41% 1,145,4 373 Street Lighting & Signal Systems 50,814,837 3.85% 2.39% 1,956,33 3eneral Plant 938,776,962 28,623,11	38 2,582,474 (3,643, 98 98 2,807,307 (2,179, 23 23 32,119 2, 23 23 283,864 (1,583, 18 18 4,992,415 (307, 88 89 1,331,433 (412, 62	,764) ,791) ,996 ,959) ,902) - 557)
365 Overhead Conductors & Devices 165,135,703 3.02% 1.70% 4,987,0 366 Underground Conduit 1,664,173 1.75% 1.93% 29,1 367 Underground Conductors & Devices 56,772,724 3.29% 0.50% 1,867,8 368 Line Transformers 219,930,197 2.41% 2.27% 5,300,3 369 Services 82,837,019 3.75% 3.75% 3,106,3 370 Meters 62,508,577 2.79% 2.13% 1,743,9 371 Installations on Customer Premises 18,268,926 6.27% 6.41% 1,145,4 373 Street Lighting & Signal Systems 50,814,837 3.85% 2.39% 1,956,3 3eneral Plant 938,776,962 28,623,11	98 2,807,307 (2,179) 23 32,119 2, 23 283,864 (1,583, 18 4,992,415 (307,) 88 3,106,388 (412,) 62 1,171,038 25,)	,791) ,996 ,959) ,902) - 557)
366 Underground Conduit 1,664,173 1.75% 1.93% 29,1 367 Underground Conductors & Devices 56,772,724 3.29% 0.50% 1,867,8 368 Line Transformers 219,930,197 2.41% 2.27% 5,300,3 369 Services 82,837,019 3.75% 3.75% 3,106,3 370 Meters 62,508,577 2.79% 2.13% 1,743,9 371 Installations on Customer Premises 18,268,926 6.27% 6.41% 1,45,4 373 Street Lighting & Signal Systems 50,814,837 3.85% 2.39% 1,956,3 3eneral Plant 20.0 k and 28,623,11	23 32,119 2, 23 283,864 (1,583, 18 4,992,415 (307,) 88 3,106,388 (412,) 62 1,171,038 25,)	996 959) 902) - 557)
367 Underground Conductors & Devices 56,772,724 3.29% 0.50% 1,867,8 368 Line Transformers 219,930,197 2.41% 2.27% 5,300,3 369 Services 82,837,019 3.75% 3.75% 3,106,3 370 Meters 62,508,577 2.79% 2.13% 1,743,9 371 Installations on Customer Premises 18,268,926 6.27% 6.41% 1,145,4 373 Street Lighting & Signal Systems 50,814,837 3.85% 2.39% 1,956,3 3eneral Plant 200 0 herd 200 0 herd 28,623,11	23 283,864 (1,583,7) 18 4,992,415 (307,7) 88 3,106,388 (412,1) 89 1,331,433 (412,1) 62 1,171,038 25,1	959) 902) - 557)
368 Line Transformers 219,930,197 2.41% 2.27% 5,300,3 369 Services 82,837,019 3.75% 3.75% 3,106,3 370 Meters 62,508,577 2.79% 2.13% 1,743,9 371 Installations on Customer Premises 18,268,926 6.27% 6.41% 1,145,4 373 Street Lighting & Signal Systems 50,814,837 3.85% 2.39% 1,956,3 Total Distribution Plant 938,776,962 28,623,11 28,623,11	18 4,992,415 (307,130,100,100,100,100,100,100,100,100,100	902) - 557)
369 Services 82,837,019 3.75% 3.75% 3.106,3 370 Meters 62,508,577 2.79% 2.13% 1,743,9 371 Installations on Customer Premises 18,268,926 6.27% 6.41% 1,145,4 373 Street Lighting & Signal Systems 50,814,837 3.85% 2.39% 1,956,3 Total Distribution Plant 938,776,962 230% 28,623,11	88 3,106,388 89 1,331,433 (412, 62 1,171,038 25,	- 557)
370 Meters 62,508,577 2.79% 2.13% 1,743,9 371 Installations on Customer Premises 18,268,926 6.27% 6.41% 1,145,4 373 Street Lighting & Signal Systems 50,814,837 3.85% 2.39% 1,956,3 Total Distribution Plant 938,776,962 239% 1,956,3 28,623,1	89 1,331,433 (412,4 62 1,171,038 25,4	
371 Installations on Customer Premises 18,268,926 6.27% 6.41% 1,145,4 373 Street Lighting & Signal Systems 50,814,837 3.85% 2.39% 1,956,3 Total Distribution Plant 938,776,962 28,623,11 28,623,11	62 1,171,038 25,	
373 Street Lighting & Signal Systems 50,814,837 3.85% 2.39% 1,956,3 Total Distribution Plant 938,776,962 28,623,10 28,623,10 Beneral Plant 200.0 h and 200.0 h and 200.0 h and 200.0 h and		576
Total Distribution Plant 938,776,962 28,623,10 Beneral Plant 200.0 km/d 28,623,10	71 1,214,475 (741,4	
	<u> </u>	_
		,
390 1 Structures 8 Improvements	•	•
200 D Improvements to Leave LD		775)
301 1 Office Europhyse & Equipment	18,146 18,1	146
301 2 Non BC Computer Emilianant (1770 200		220)
391.3 Cash Processing Equipment		-
301 / Borcopol Computer Equipment	58 39,898 _{)/} (41,8	360)
302 Transportation Equipment	46 3,904,946	-
393 Stores Equipment	4.749,848	-
304 Tool Shop and Carera Equipment		926)
395 Laboratory Equipment		
396 Power Operated Environment		•
397 Communication Equipment	-,	037
398 Misc Equipment		
Jotal General Plant 463,335 5.19% 0.00% 24,04 I 113,162,212 13,154,58	(21)0	
TOTAL PLANT excluding ARO Assets 3,178,796,889	i9 12,630,360 (524,2	:29)
ARO Assets excluded from Plant in service 8,608,030		
Total Plant in Service 3,187,404,919		
Total Annual Depreciation 107,112,50	8 79,768,777 (27,343,7	(30)
Less Amounts not included in Income Statement Depreciation Coal Cars		
Brown Gas Pipeline 351,00	8 152,180 (198,8)	28)
TC Gas Pipeline 283,54		,
Account 139200 Transportation Equipment 4,749,84	8 4,749,848 -	
5,537,88	6 5,470,832 (67,0	54)
Less ECR Depreciation 194,43	4 223,677 29,24	43
Total Annualized Depreciation 101,380,18	7 74,074,268 (27,305,9	18)

Kentucky Utilities Company Annualized Depreciation at September 30, 2003 Using Historical Gross Salvage and Cost of Removal and Removing Interim Additions for NOX Compliance

Pro Forma Depreciation Adjustment 98.724,719 Depreciation 98.724,719 Amonization 98.724,719 Amonization 98.724,719 Liss Depreciation SFAS 143 Assets (131.238) Liss Depreciation of CR Assets (131.238) Liss Depreciation of CR Assets (131.238) Liss Depreciation of CR Assets (131.238) Liss Depreciation under current rates 100.988,171 11 Adjustment due to annual/dirg current rates (101.389,187) 12 months depreciation under current rates (20.776,770) Liss Annualized Depreciation under current rates (20.776,770) Citil Adjustment (1) + (2) (20.304,154) KU Proposed rates (20.304,154) (1) Total Net Difference Between KUC Adjustment for Gross Salv/COR (22.599,459) Total Adjustment (1) + (2) (20.304,154) KU Proposed Adjustment (1) + (2) (20.304,154) KU Proposed Adjustment for Gross Salv/COR (22.599,459) Total Adjustment (1) + (2) (20.304,154) KU Proposed Adjustment (1) + (2) (20.304,154) KU Proposed Adjustment (1) + (2) (20.304,154) KU Proposed Adjustment (1) + (2) (20			Depreciable Balance 09/30/03	KIUC Rates W/Adjust. Gross Salv/COR	Proposed Rates KIUC	Depreciation Under KIUC Rates W/Adjust. Gross Salv/COR	Depreciation Under KIUC Rates	Net Difference KIUC Rates W/Adjust. Gross Salv/COR/ KIUC Rates
Twelve months ended 9000 per books 96,724,719 Amoutization 96,724,719 Amoutization 4,509,128 Less Depreciation SFAS 1/43 Assets (131,239) Less Depreciation of ECR Assets (131,239) Less Depreciation under current rates 100,080,171 Annualized Depreciation under current rates 100,080,171 (1) Adjustment due to annualizing current rates 101,380,167 12 months depreciation under current rates 80,604,017 (1) Adjustment due to annualizing current rates 200,776,170) 12 months depreciation under current rates 200,776,170) (2) Adjustment (1) + (2) 20,024,154) KU Proposed Adjustment 2,395,555 (3) Total Adjusted by KIUC for Gross Salv/COR 22,698,689) Total Annualized Depreciation Adjusted by KIUC for Gross Salv/COR Adjustment 23,95,555 (1) Total Annualized Depreciation Adjusted by KIUC for Gross Salv/COR Adjustment 22,698,689) Total Adjustment (1) + (2) 22,698,689) Total Annualized Depreciation Adjusted by KIUC for Gross Salv/COR Adjustment (22,698,689) (1) Total Annualized Depreciation Adjusted by KIUC for Gross Salv/COR Adjustment (22,698,689) Total Annualized Depreciation Adjust	Pro Forma Depreciation	n Adjustment						
Depreciation 96,724,719 Amoritation 4,509,129 Less Depreciation SFAS 143 Assets 4,509,129 Less Depreciation of ECR Assets (114, 439) Instance (114, 439) Amountable of Depreciation under current rates (119, 380, 167) 10 109,989,171 113,380,167 (113,380, 167) 12 months depreciation under Current rates 472,016 12 months depreciation under CUrrent rates (101,380, 167) 12 C20,776,170) (101,380, 167) 13 Total Adjustment (1) + (2) (20,394, 154) KU Proposed Adjustment 2,395,535 13 Total Annualized Depreciation Adjusted by KIUC for Removal of NOX Compliance Interim Additions 74,074,288 14 Month Adjusted by KIUC for Gross Sativ/COR Adjustment (80,504,077) 14 Annualized Depreciation Adjusted by KIUC for Gross Sativ/COR Adjustment (80,504,077) 14 Annualized Depreciation Adjusted by KIUC for Gross Sativ/COR Adjustment (80,504,077) 14 Total Annualized Depreciation Adjusted Di NOX			-					
Amotizzation 6867247/19 Less Depreciation OFECR Assets 4509, 123 Less Depreciation OFECR Assets (131328) (131328) Less Depreciation under current rates (131328) (1380,167 (1) Adjustment due to annualzing current rates (1320,000,000,000,000,000,000,000,000,000,		-						
Less Deprediation SFAS 143 Assets 4.609, 1289 Less Deprediation of ECR Assets (191, 289) Annualized Deprediation under current rates 100, 988, 171 100, 988, 171 100, 988, 171 101, 280, 167 100, 988, 171 11, 200, 100, 100, 100, 100, 100, 100, 1								
Less: Depreciation of ECR Assets (131,230) (184,436) Annualized Depreciation under current rates 100,908,171 (1) Adjustment due to annualizing current rates 472,016 12 months depreciation under KIUC rates ADJUSTED FOR Gross Sativ/COR Loss: Annualized Depreciation under current rates 80,604,017 (10) Adjustment due to proposed rates (20,776,170) (10) Total Adjustment (1) + (2) (20,2776,170) Total Adjustment (1) + (2) (20,204,154) KU Proposed Adjustment for Gross Sativ/COR (22,599,555) Total Annualized Depreciation Adjusted by KIUC for Removal of NOX Compliance Interim Additions 74,074,288 Total Annualized Depreciation Adjusted by KIUC for Gross Sativ/COR adjustment (8,529,749) Total Annualized Depreciation Adjusted by KIUC for Gross Sativ/COR adjustment (29,229,435) Kentucky Jurisdiction Percentage (29,229,435) Kentucky Jurisdiction Percentage (29,229,435)								
Annualized Depreciation under current rates (194.435) 100.900.171 100.900.171 101.940.167 101.940.167 (1) Adjustment due to annualizing current rates 472.016 12 monthis depreciation under KIUC rates ADJUSTED FOR Gross SativCOR 80.604.017 Less Annualized Depreciation under current rates 60.604.017 (2) Adjustment due to proposed rates (20.776.170) Total Adjustment (1) + (2) (20.304.154) KU Proposed Adjustment 2.399.535 (3) Total Net Difference Between KIUC Adjustment for Gross SativCOR (22.599.689) Total Annualized Depreciation Adjusted by KIUC for Removal of NOX Compliance Interim Additions 74.374.268 Total Net Difference Between KIUC Adj. For Gross Sativ/COR & Removal of NOX Compliance Interim Additions 74.374.268 Total Net Difference Between KIUC Adj. For Gross Sativ/COR & Removal of NOX Compliance Interim Additions 74.374.268 Total Net Difference Between KIUC Adj. For Gross Sativ/COR & Removal of NOX Compliance Interim Additions (23.229.438) Total Net Difference Between KIUC Adj. For Gross Sativ/COR & Removal of NOX Compliance Interim Additions (23.229.438) Total Net Difference Between KIUC Adj. For Gross Sativ/COR & Removal of NOX Compliance Interim Additions (23.229.438) Kentucky Jurisdiction Percentage								(131,239)
Annualized Depretation under current rates 101,380,167 (1) Adjustment due to annualizing current rates 472,016 12 months depredation under KIUC rates ADJUSTED FOR Gross Salv/COR 80,604,017 Less: Annualized Depreciation under current rates (101,380,167) (2) Adjustment due to proposed rates (20,776,170) Total Adjustment (1) + (2) (20,304,154) KU Proposed Adjustment 2,396,535 (3) Total Net Difference Between KIUC Adjustment for Gross Salv/COR (22,699,689) Total Annualized Depreciation Adjusted by KIUC for Removal of NOX Compliance Interim Additions 74,074,288 (4) Total Net Difference Between KIUC Adj. For Gross Salv/COR & Removal of NOX Compliance (6,529,749) (4) Total Net Difference Between KIUC Adj. For Gross Salv/COR & Removal of NOX Compliance (29,229,438) KU Proposed Adjustment (3) + (4) (29,229,438) Total Net Difference Between KIUC Adj. For Gross Salv/COR & Removal of NOX Compliance (29,229,438) Kentucky Jurisdiction Percentage 87,299%								
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12 months depreciation under KIUC rates ADJUSTED FOR Gross Satv/COR 80.604,017 Less-Annualized Depreciation under current rates (101.380,187) (2) Adjustment due to proposed rates (20.776,170) Total Adjustment (1) + (2) (20.304,154) KU Proposed Adjustment 2,395,535 (3) Total Net Difference Between KIUC Adjustment for Gross Satv/COR (22,599,689) Total Annualized Depreciation Adjusted by KIUC for Removal of NOX Compliance Interim Additions 74,074,288 Total Annualized Depreciation Adjusted by KIUC for Gross Satv/COR & Removal of NOX Compliance (6,529,749) (4) Total Net Difference Between KIUC Adj. For Gross Satv/COR & Removal of NOX Compliance (6,529,749) Total Net Difference Between KIUC Adj. For Gross Satv/COR & Removal of NOX Compliance (6,529,749) Total Net Difference Between KIUC Adj. For Gross Satv/COR & Removal of NOX Compliance (25,229,438) KU Proposed Adjustment (3) + (4)		Contrast and of barrant fates						101,380,187
12 months depreciation under KIUC rates ADJUSTED FOR Gross Saty/COR 80,664,017 Less-Annualized Depreciation under current rates (101,380,187) (2) Adjustment due to proposed rates (20,776,770) Total Adjustment (1) + (2) (20,304,154) KU Proposed Adjustment 2,395,535 (3) Total Net Difference Between KIUC Adjustment for Gross Saty/COR (22,599,659) Total Annualized Depreciation Adjusted by KIUC for Removal of NOX Compliance Interim Additions 74,074,268 Total Annualized Depreciation Adjusted by KIUC for Gross Saty/COR & Removal of NOX Compliance (6,529,749) (4) Total Net Difference Between KIUC Adj. For Gross Saty/COR & Removal of NOX Compliance (6,529,749) Total Net Difference Between KIUC Adj. For Gross Saty/COR & Removal of NOX Compliance (6,529,749) Total Net Difference Between KIUC Adj. For Gross Saty/COR & Removal of NOX Compliance (29,229,438) KU Proposed Adjustment (3) + (4) (4) Kentucky Jurisdiction Percentage 87,299%	(1) Adjustment d	lue to annualizing current retes						
Less Annualized Depreciation under current rates a000,00,00 (101,000,00,00) (2) Adjustment due to proposed rates (20,776,170) Total Adjustment (1) + (2) (20,076,170) KU Proposed Adjustment (20,304,154) (3) Total Net Difference Between KIUC Adjustment for Gross Salv/COR (22,699,689) Total Annualized Depreciation Adjusted by KIUC for Removal of NOX Compliance Interim Additions 74,074,268 (4) Total Net Difference Between KIUC Adj. For Gross Salv/COR & Removal of NOX Compliance (6,529,749) (80,564,017) (4) Total Net Difference Between KIUC Adj. For Gross Salv/COR & Removal of NOX Compliance (6,529,749) (22,292,438) Total Net Difference Between KIUC Adj for Gross Salv/COR with Removal of NOX Compliance (29,228,438) (29,228,438) Kentucky Jurisdiction Percentage 87,299%	()							472,016
Less Annualized Depreciation under current rates a000,00,00 (101,000,00,00) (2) Adjustment due to proposed rates (20,776,170) Total Adjustment (1) + (2) (20,076,170) KU Proposed Adjustment (20,304,154) (3) Total Net Difference Between KIUC Adjustment for Gross Salv/COR (22,699,689) Total Annualized Depreciation Adjusted by KIUC for Removal of NOX Compliance Interim Additions 74,074,268 (4) Total Net Difference Between KIUC Adj. For Gross Salv/COR & Removal of NOX Compliance (6,529,749) (80,564,017) (4) Total Net Difference Between KIUC Adj. For Gross Salv/COR & Removal of NOX Compliance (6,529,749) (22,292,438) Total Net Difference Between KIUC Adj for Gross Salv/COR with Removal of NOX Compliance (29,228,438) (29,228,438) Kentucky Jurisdiction Percentage 87,299%								
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& KU Proposed Adjustment (3) + (4) Kentucky Jurisdiction Percentage 87.299%								(6,529,749)
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& KU Proposed Adjustment (3) + (4) Kentucky Jurisdiction Percentage 87.299%	Total Net Differe	nce Between KIUC Adj for Gross Salv/C	COR with Removal of NO	X Compliance				
Kentucky Jurisdiction Percentage 87.299%	& KU Proposed /	Adjustment (3) + (4)						(29,229,438)
Kentucky Jurisdiction Amount								
Kentucky Jurisdiction Amount	Kentucky Jurisd	Iction Percentage						
Kentucky Jurisdiction Amount(25,517,007)		÷						87.299%
(26,517,007)	Kentucky Jurisd	iction Amount						
	-							(26,517,007)

Exhibit___(LK-7)

Kentucky Utilities Company Capitalization and Return Requirements At September 30, 2003

Rate of Return as Filed by KU

	Capital Amounts	Capital Ratios	Component Costs	Wtd Avg Cost	Convers Factor	Grossed Up Wtd Avg Cost
Short Term Debt A/R Securitization Long Term Debt Preferred Stock Common Equity Total	77,825,772 38,856,247 483,733,595 31,531,735 686,177,634 1,318,124,983	5.90% 2.95% 36.70% 2.39% 52.06%	1.06% 1.39% 3.12% 5.68% 11.25%	0.06% 0.04% 1.14% 0.14% 5.86%	1.006769 1.006769 1.006769 1.688147 1.688147	0.06% 0.04% 1.15% 0.23% 9.89%
Return Requirement before Return Requirement after of	e Gross-Up	100.00%		7.24% 95,443,530		11.27% 148,534,579

Rate of Return with KIUC Return on Common Equity

	Capital Amounts	Capital Ratios	Component Costs	Wtd Avg Cost	Convers Factor	Grossed Up Wtd Avg Cost
Short Term Debt	77,825,772	5.90%	1.06%	0.06%	1.006769	0.06%
A/R Securitization	38,856,247	2.95%	1.39%	0.04%	1.006769	0.06%
Long Term Debt	483,733,595	36.70%	3.12%	1.14%	1.006769	1.15%
Preferred Stock	31,531,735	2.39%	5.68%	0.14%	1.688147	0.23%
Common Equity	686,177,634	52.06%	8.70%	4.53%	1.688147	7.65%
Total	1,318,124,983	100.00%		5.91%		9.03%
Return Requirement before	e Gross-Up			77,946,000		
Return Requirement after (Gross-Up					118,996,181
Reduction in Revenue Req Effect of Each 1% ROE	uirement					29,538,398 11,583,685

AMERICAN ELECTRIC POWER		Exhibit(LK-8 Page 1 of 2
	ORIGINAL	SHEET NO 19-1
	CANCELLING	SHEET NO 19-1
		P.S.C. ELECTRIC NO. 7
	TARIFF B. S. C.	
APPLICABLE.	(System Salas Clause)	
To Tariffa R.S., R.SL.H	T.D.D., Experimental R.S. T.D.D.	S.G.S., N.G.S., Experimental M.G.ST.O.D
L.G.S., O.P., C.I.P. T.O.D., I.R RATE.	.P., M.W., O.L., and S.L.	a.G.S., M.G.S., Experimental M.G.ST.O.
1. When the much is an		
system sales, as provided in part and a system sales adjustment fa kilowatthour, is defined as set f	avenues from system sales are above a agraph 3 below, an additional credit actor (A) shall be made, where "A", forth below.	or below the monthly base net revenues fr or charge equal to the product of the Kwh calculated to the nearest 0,0001 mill p
\$yz	tem Sales Adjustment Factor (A) = (.	
In the above formula #T	* 18 Kentucky Bound Tor	JUM - TD])/Sm
the current (m) and base (b) perio	ods and "S" is the Kwh sales in the	- monthly net revenues from system sales - current (m) period, sil defined below.
are channed by and revenue from Am	Prican Electric Rowan datas a	Particuly with Deringer Delow.
short consist of and be derived as	follows:	ats under Account 447, Sales for Berate
a. KPCo's Nember Load	Ratio share of total revenues from	System sales as recorded in Account 447
		system sales as recorded in Account 447
b, KPEO's Member Load energy for the deli-	Ratio share of total out-of-pocket	costs incurred in supplying the power and
The Duteofermelies		
		ance, tax, transmission losses and other and energy had not been supplied for such
	asts include all operating, mainten not have been incurred if the power ag demand and energy charges for power nues from system sales are as follow	ance, tax, transmission losses and other and energy had not been supplied for such
	mues from system sales are as follow Base Not Revenues from	ance, tax, transmission losses and other and energy had not been supplied for such ar and energy supplied by Third Parties. MS:
The base monthly net reve	nues from system sales are as follow Base Net Revenues from System Sales	ance, tax, transmission losses and other and energy had not been supplied for such ar and energy supplied by Third Parties. MS:
3. The base monthly net reve Billing <u>Honth</u>	nues from system sales are as follow Base Nat Revenues from System Sales (Total Company Basis)	ance, tax, transmission tosses and other and energy had not been supplied for such an and energy supplied by Third Parties. re: PUBLIC SEDIMON
3. The base monthly net reve Billing <u>Month</u> January	nues from system sales are as follow Base Nat Revenues from System Sales (Total Company Basis) \$ 895,960	ance, tax, transmission losses and other and energy had not been supplied for such ar and energy supplied by Third Parties. As: PUBLIC SERVICE COMMISSION
 The base monthly net reve Billing <u>Honth</u> 	nues from system sales are as follow Base Nat Revenues from System Sales (Total Company Basis) \$ 895,960 767,802	ance, tax, transmission losses and other and energy had not been supplied for such ar and energy supplied by Third Parties. As: PUBLIC SERVICE COMMISSION
 The base monthly net reve Billing <u>Honth</u> January February 	nues from system sales are as follow Base Nat Revenues from System Sales (Total Company Basis) \$ 895,960 767,802 893,126	ance, tax, transmission losses and other and energy had not been supplied for such ar and energy supplied by Third Parties. As: PUBLIC SERVICE COMMISSION OF KENTUCKY EFFECTIVE
3. The base monthly net reve Billing <u>Month</u> January February March	nues from system sales are as follow Base Nat Revenues from System Sales (Total Company Basis) \$ 895,960 767,802 893,126 1,036,738	ance, tax, transmission losses and other and energy had not been supplied for such ar and energy supplied by Third Parties. As: PUBLIC SERVICE COMMISSION OF KENTUCKY EFFECTIVE
3. The base monthly net reve Billing Month January February March April	nues from system sales are as follow Base Net Revenues from System sales <u>(Total Company Basis)</u> \$ 895,960 767,802 893,126 1,036,738 1,085,852	ance, tax, transmission losses and other and energy had not been supplied for such ar and energy supplied by Third Parties. As: PUBLIC SERVICE COMMISSION OF KENTUCKY EFFECTIVE
3. The base monthly net reve Billing Month January February March April May	nues from system sales are as follow Base Nat Revenues from System Sales (Total Company Basis) \$ 895,960 767,802 893,126 1,035,738 1,085,852 1.324,166	ance, tax, transmission losses and other and energy had not been supplied for such ar and energy supplied by Third Parties. BE: PUBLIC SERVICE COMMISSION OF KENTUCKY EFFECTIVE
3. The base monthly net reve Billing Month January February March April Kay June	solution and the provided from the set of th	ance, tax, transmission losses and other and energy had not been supplied for such ar and energy supplied by Third Parties. BE: PUBLIC SERVICE COMMISSION OF KENTUCKY EFFECTIVE
3. The base monthly net reve Billing <u>Honth</u> January February March April May June July August	State and a set of the set of th	ance, tax, transmission losses and other and energy had not been supplied for such ar and energy supplied by Third Parties. PUBLIC SERVICE COMMISSION OF KENTUCKY EFFECTIVE MAR 2 7 1996 PURSUANT TO 2
3. The base monthly net reve Billing <u>Month</u> January February March April May June July	Charles from system sales are as follow Base Net Revenues from System Sales <u>(Totel Company Basis)</u> \$ 895,960 767,802 893,126 1,036,738 1,085,852 1,324,166 1,027,403 1,154,184 912,736	ance, tax, transmission losses and other and energy had not been supplied for such ar and energy supplied by Third Parties. PUBLIC SERVICE COMMISSION OF KENTUCKY EFFECTIVE MAR 2 7 1996 PURSUANT TO 807 KAR Source
3. The base monthly net reve Billing Month January February March April Kay June July August Saptember	Charles from system sales are as follow Base Not Revenues from System Sales <u>(Total Company Basis)</u> \$ 895,960 767,802 893,126 1,036,738 1,085,852 1,324,166 1,027,403 1,154,184 912,736 731,014	Ance, tax, transmission losses and other and energy had not been supplied for such ar and energy supplied by Third Parties. PUBLIC SERVICE COMMISSION OF KENTUCKY EFFECTIVE MAR 0.1 1996 PURSUANT TO 807 KAR 5011
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3. The base monthly net reve Billing <u>Honth</u> January February March April May June July August September October Hovember December	Charles from system sales are as follow Base Not Revenues from System sales <u>(Total Company Basis)</u> \$ 895,960 767,802 893,126 1,026,738 1,025,403 1,154,184 912,736 731,014 624,320 862,035	Ance, tax, transmission losses and other and energy had not been supplied for such ar and energy supplied by Third Parties. PUBLIC SERVICE COMMISSION OF KENTUCKY EFFECTIVE MAR 0 1 1996 PURSUANT TO 807 KAR 5011. SECTION 9 (1) FOR THE RUBLIC SERVICE COMMISSION
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ANERICAN ELECTRIC POWER	ORIGINAL	Page 2 o
	CANCELLING	SHEET NO 19-2
		P.B.C. ELECTRIC NO. 7
	TARIFF S. S. C. (Cor (System Sales Elbu	/sc)
and a second sec	ata and information as may be r	h the Commission ten (10) days before upporting data to justify the amount o equired by the Commission.
		Commission under this regulation shall be he Public Service Commission pursuant t
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		PUBLIC REPU
		PUBLIC SERVICE COMM OF KENTUCKY EFFECTURE
		EFFECTIVE
		MAR 2 7 1996
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		PURSUANT TO 807 KAR 5011, SECTION 9 (1) BY:
		BY: CECTION 8 (1) FOR THE PUBLIC SUIVICE COMMISSION
DATE OF ISSUE January 30, 1996		ISSION
SSUED BY E. K. WAGNER	DIRECTOR OF BATES	e rendered on and after April 1, 1991

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Exhibit (LK-9) Page 1 of 2

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Tales, subject to subsequent adjustment factor shall be based upon astimated monthly revenues and costs for system (Cont/d, on Sheet No. 19-2) ATE OF ISSUE JERNARY 30, 1996 DATE EFFECTIVE AUgust 2, 1995				SHEET NO
APPLICABLE. R.SL. MT.D.D., Experimental R.ST.O.D., B.G.S., M.G.S., Experimental M.G.ST.O. ANTE. I. O.S., D.F., CLIP-T.O.D., I.R.P., M.M., OLL, and S.L. I. O.S., D.F., CLIP-T.O.D., I.R.P., M.M., OLL, and S.L. ANTE. I. When the monthly net revenues from system sales are above or below the monthly bers net revenues from system sales and interesting the control of a shall be made, where the calculated to the product of the RM and a postem sales afjustment factor (A) a (.SITm - TD)/Sm In the above formid are is forth below. System Sales Adjustment factor (A) a (.SITm - TD)/Sm In the above formids are is forth below. System Sales Adjustment factor (A) a (.SITm - TD)/Sm In the above formids are in the formed of the product of the product of the form system sales at the current (n) and base (b) periods and the factor (A) a (.SITm - TD)/Sm In the above formids are in the formed at the sales in the their Member Load factor formanies the formed at fragmentian filled for for production to their Member Load factor factor factor for factor (A) a (.SITm - TD)/Sm In the above formids are in their frequences from system sales as recorded in Account (I) and as reported above for factor (A) a (.SITm - Market A) and as reported above of the factor (A) a (.SITm - Market A) and as reported above of the factor (A) a (.SITm - Market (A) (.SITm - Market (A) (.SITm - Market (A) (.SITm - Market (A) (.SITm				P.S.C. ELECTRIC NO. 7
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P.S.C. ELECTRIC NO. 7

TARIEF S. S. C. (Cont'd.) (System Sales Clause)

AMERICAN ELECTRIC POWER

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6. The monthly System Sales Clause shall be filed with the Commission ten (10) days before it is acheduled to so into effect, along with all the necessary supporting data to justify the amount of the adjustments which shall include data and information as may be required by the Commission.

7. Copies of all documents required to be filed with the Commission under this regulation shall be open and made available for public inspection at the office of the Public Service Commission pursuant to the provisions of ERS 61.870 to 61.884.

	PUBLIC SERVICE COMMISSIO OF KENTUCKY EFFECTIVE
	MAR D 1 1996 FURSUANT TO BOT KAR 5011
DATE OF ISSUE	DATE EFFECTIVE Service rendered on and after April 1, 1991 DIRECTOR OF RATES ADDRESS Ublic Service Commission in Case No. 91-066 dated April 1, 1991