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COMMONWEALTH OF KENTUCKY MAR 2 3 2004

BEFORE THE PUBLIC SERVICE COMMISSION

IN THE MATTER OF:

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

DIRECT TESTIMONY

AND EXHIBITS

OF

STEPHEN J. BARON

ON BEHALF OF

KENTUCKY INDUSTRIAL UTILITY CUSTOMERS, INC.

J. KENNEDY AND ASSOCIATES, INC. ROSWELL, GEORGIA

March 2004

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1

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DIRECT TESTIMONY OF STEPHEN J. BARON

I. QUALIFICATIONS AND SUMMARY

2	Q.	Please state your name and business address.
3		
4	A.	My name is Stephen J. Baron. My business address is J. Kennedy and Associates,
5		Inc. ("Kennedy and Associates"), 570 Colonial Park Drive, Suite 305, Roswell,
6		Georgia 30075.
7		
8	Q.	What is your occupation and by who are you employed?
9		

1	A.	I am the President and a Principal of Kennedy and Associates, a firm of utility rate,
2		planning, and economic consultants in Atlanta, Georgia.
3		
4	Q.	Please describe briefly the nature of the consulting services provided by
5		Kennedy and Associates.
6		
7	A.	Kennedy and Associates provides consulting services in the electric and gas utility
8		industries. Our clients include state agencies and industrial electricity consumers.
9		The firm provides expertise in system planning, load forecasting, financial analysis,
10		cost-of-service, and rate design. Current clients include the Georgia and Louisiana
11		Public Service Commissions, and industrial consumer groups throughout the United
12		States.
13		
14	Q.	Please state your educational background.
15		
16	A.	I graduated from the University of Florida in 1972 with a B.A. degree with high
17		honors in Political Science and significant coursework in Mathematics and
18		Computer Science. In 1974, I received a Master of Arts Degree in Economics, also
19		from the University of Florida. My areas of specialization were econometrics,
20		statistics, and public utility economics. My thesis concerned the development of an

1		econometric model to forecast electricity sales in the State of Florida, for which I
2		received a grant from the Public Utility Research Center of the University of
3		Florida. In addition, I have advanced study and coursework in time series analysis
4		and dynamic model building.
5		
6	Q.	Please describe your professional experience.
7		
8	A.	I have more than twenty-nine years of experience in the electric utility industry in
9		the areas of cost and rate analysis, forecasting, planning, and economic analysis.
10		
11		Following the completion of my graduate work in economics, I joined the staff of
12		the Florida Public Service Commission in August of 1974 as a Rate Economist. My
13		responsibilities included the analysis of rate cases for electric, telephone, and gas
14		utilities, as well as the preparation of cross-examination material and the preparation
15		of staff recommendations.
16		
17		In December 1975, I joined the Utility Rate Consulting Division of Ebasco Services,
18		Inc. as an Associate Consultant. In the seven years I worked for Ebasco, I received
19		successive promotions, ultimately to the position of Vice President of Energy
20		Management Services of Ebasco Business Consulting Company. My

responsibilities included the management of a staff of consultants engaged in 1 providing services in the areas of econometric modeling, load and energy 2 cost-of-service analysis, production cost modeling, planning, forecasting. 3 cogeneration, and load management. 4 5 I joined the public accounting firm of Coopers & Lybrand in 1982 as a Manager of 6 the Atlanta Office of the Utility Regulatory and Advisory Services Group. In this 7 capacity I was responsible for the operation and management of the Atlanta office. 8 My duties included the technical and administrative supervision of the staff, 9 budgeting, recruiting, and marketing as well as project management on client 10 At Coopers & Lybrand, I specialized in utility cost analysis, engagements. 11 forecasting, load analysis, economic analysis, and planning. 12 13 In January 1984, I joined the consulting firm of Kennedy and Associates as a Vice 14 President and Principal. I became President of the firm in January 1991. 15 16 During the course of my career, I have provided consulting services to more than 17 18 thirty utility, industrial, and Public Service Commission clients, including three 19 international utility clients. 20

1		I have presented numerous papers and published an article entitled "How to Rate
2		Load Management Programs" in the March 1979 edition of "Electrical World." My
3		article on "Standby Electric Rates" was published in the November 8, 1984 issue of
4		"Public Utilities Fortnightly." In February of 1984, I completed a detailed analysis
5		entitled "Load Data Transfer Techniques" on behalf of the Electric Power Research
6		Institute, which published the study.
7		
8		I have presented testimony as an expert witness in Arizona, Arkansas, Colorado,
9		Connecticut, Florida, Georgia, Indiana, Kentucky, Louisiana, Maine, Michigan,
10		Minnesota, Maryland, Missouri, New Jersey, New Mexico, New York, North
11		Carolina, Ohio, Pennsylvania, Texas, West Virginia, Federal Energy Regulatory
12		Commission and in United States Bankruptcy Court. A list of my specific
13		regulatory appearances can be found in Baron Exhibit(SJB-1)
14		
15	Q.	Would you please discuss your experience in electric utility restructuring
16		proceedings?
17		
18	A.	I have been extensively involved in electric utility restructuring since 1995. This
19		involvement includes participation in eight proceedings in Pennsylvania, seven of
20		which involved detailed implementation analyses associated with restructuring. In

1	these cases, I addressed stranded costs, regulatory policy associated with retail
2	competition and restructuring implementation, and rate unbundling. The utilities
3	included PECO Energy, Pennsylvania Power & Light Company, West Penn Power
4	Company, Metropolitan Edison Company, Pennsylvania Electric Company and
5	Duquesne Light Company.
6	
7	I have also been involved in restructuring proceedings in the State of Maryland
8	associated with Baltimore Gas & Electric Company and Potomac Edison Company.
9	In addition, I participated in a generic proceeding before the Maryland Public
10	Service Commission on electric utility restructuring and have testified before the
11	Maryland Legislature on this issue.
12	In 1999, I was involved in restructuring proceedings in West Virginia associated
13	with the Appalachian Power subsidiary of AEP and Monongahela Power Company,
14	a subsidiary of Allegheny Power Company. I also participated in restructuring
15	proceedings in Connecticut involving United Illuminating Company and
16	Connecticut Light and Power Company. In 2000, I participated in electric
17	restructuring proceedings in Ohio involving First Energy Corporation and Cinergy.
18	
19	In Louisiana, I have been involved in the Entergy Gulf States, Inc. ("EGSI")
20	stranded cost proceeding and in the Commission's generic proceeding on retail

1		competition. I have addressed issues on stranded cost quantification, standard offer
2		tariffs, load profiling and other issues.
3		
4		To date, I have presented testimony in 13 electric restructuring proceedings.
5		
6	Q.	On whose behalf are you testifying in this proceeding?
7		
8	A.	I am testifying on behalf of the Kentucky Industrial Utility Customers ("KIUC"), a
0	11.	
9		group of large industrial customers taking service on the LG&E and KU systems.
10		
11	Q.	How have you organized your testimony with regard to LG&E and KU issues?
11 12	Q. A.	How have you organized your testimony with regard to LG&E and KU issues? For many of the issues that I will discuss, I present common testimony that is
	_	
12	_	For many of the issues that I will discuss, I present common testimony that is
12 13	_	For many of the issues that I will discuss, I present common testimony that is applicable to both LG&E and KU. This would include discussions of basic
12 13 14	_	For many of the issues that I will discuss, I present common testimony that is applicable to both LG&E and KU. This would include discussions of basic principles associated with cost allocation and rate design as well as a number of
12 13 14 15	_	For many of the issues that I will discuss, I present common testimony that is applicable to both LG&E and KU. This would include discussions of basic principles associated with cost allocation and rate design as well as a number of other issues, including interruptible and curtailable rates. However, since the
12 13 14 15 16	_	For many of the issues that I will discuss, I present common testimony that is applicable to both LG&E and KU. This would include discussions of basic principles associated with cost allocation and rate design as well as a number of other issues, including interruptible and curtailable rates. However, since the revenue requirement requests and the specific cost of service study results for

1		For the purposes of organizing my testimony, when I am discussing an issue that is
2		common to both LG&E and KU, I will refer to these companies as ("the Company"
3		or the "Companies"). For a specific LG&E and KU issues I will refer to each
4		Company by name (LG&E or KU).
5		
6	Q.	What is the purpose of your testimony?
7		
8	A.	I am presenting testimony on a variety of cost of service and rate design issues
9		raised by the Company's filings in this case. The first issue that I address concerns
10		the Company's filed cost of service study using the base-intermediate-peak ("BIP")
11		class cost of service methodology. I will discuss some specific corrections that I
12		have made to the Company's study due to data anomalies that were uncovered in
13		our analysis (in the case of the KU study), as well as three corrections to the
14		methodology itself (LG&E and KU). In addition, I will discuss some general
15		concerns that KIUC has with the BIP method from a methodological standpoint.
16		However, in order to facilitate the principle recommendation that KIUC is making
17		with regard to rate class revenue allocation in this case, KIUC will accept the BIP
18		method as the basis for our revenue apportionment recommendation to rate classes.

In order to develop an understanding of the subsidies that are currently being paid 1 and received by various rate classes on the Company's two systems, I also present a 2 number of alternative cost of service studies based on: 1) the average and excess 3 method. 2) the summer/winter coincident peak method, 2) the summer coincident 4 peak method and 4) the 12 CP method. The purpose of these presentations is to 5 show that under a variety of cost of service studies, the Company's current rate 6 design and its revenue apportionment proposal does not adequately address the 7 subsidies currently in the Company's rates. As I will show, under each of these 8 alternative cost of service studies, the residential class is substantially underpaying 9 its costs while large commercial and industrial customers are substantially over 10 paying for electric service. Regulatory commissions are sometimes reluctant to rely 11 on a single cost of service study to form a strict revenue apportionment policy. 12 However, in this case, I will show that under a number of cost of service 13 methodologies that are commonly used in the electric utility industry, residential 14 customers are substantially underpaying for electric service and large consumers are 15 substantially overpaying. 16

17

18 My testimony specifically addresses the revenue allocation or apportionment 19 methodology relied upon by the Company in this case to establish the increases for 20 each rate schedule. Though the Company apparently considers the cost of service

results from the BIP method, it has arbitrarily decided that the residential class 1 should not receive an increase greater than 1% above the system average. This 2 criterion does not adequately mitigate the significant disparities between rates and 3 cost of service among the rate classes for either KU or LG&E. I will recommend an 4 alternative methodology that should be adopted that would specifically reduce the 5 subsidies by 25% through the allocation of any increase approved by the 6 Commission. In this manner, the revenue apportionment will move class rates of 7 return under the BIP method towards cost of service, although at a relatively slow 8 9 pace.

10

The next set of issues that I will address concerns the Company's proposed rate design for large commercial and industrial customers. KIUC generally accepts the Company's rate design proposals and recommends that the basic structure proposed by each of the Companies be adopted. The Company has reduced energy charges and applied increases in this case to the demand charges of these large customer rates.

Following this general policy, KIUC is recommending that any reduction in the allocated increase to each of these large rate schedules be applied only to the demand charges, leaving the energy charge as proposed by the Company. I will also address the proposed new riders being offered by the Company in each of its

jurisdictions that would be applicable to large commercial and industrial customers. For the most part, these new riders do not have a material current impact on customers in this case, but could do so in the future. My testimony on these issues does not recommend rejecting the riders, but rather a clarification of the Company's intention, where applicable, not to apply the riders to existing customer arrangements.

7

The next issue that I address concerns the Company's proposal to modify its 8 interruptible rates under the curtailable service rider ("CSR"). The Company is 9 proposing to substantially modify its interruptible and curtailable rates by increasing 10 the maximum number of hours of interruption to 500 hours per year and reducing 11 substantially (in the case of KU) the notice period required for interruption requests. 12 The Company is proposing to increase the interruptible credit for both LG&E and 13 KU. I will address each of these issues as well as some additional modifications to 14 each Company's CSR tariff. In particular, my analysis of the Company's responses 15 to KIUC data requests indicates that the maximum annual hours of interruption 16 should be substantially less than the Company's proposed 500-hour annual 17 maximum. I will also discuss a KIUC proposal to offer a buy-through option that 18 would permit interruptible customers to purchase power at market rates in the event 19

2

of a call for interruption, when such interruption is for the purpose of economic savings to each of the Companies, rather than for reliability.

3

The final issue that I will address concerns the special contract between 4 MeadWestvaco and Kentucky Utilities Company. KU's cost of service study, and 5 all of the cost-of-service studies that I developed consistently show that the KU 6 special contract customer class is being substantially overcharged. Despite this, KU 7 proposes a rate increase to MeadWestvaco that exceeds both the system average 8 increase and the increase for Rate Schedule LCI-TOD, the otherwise most nearly 9 applicable tariff. KU's proposal is based on an incomplete and flawed analysis 10 which ignores the contractual consideration provided by the customer and which 11 would effectively negate the value of the Commission approved contract. 12 Therefore, each special contract in the rate class should receive a below average 13 increase based on my 25% subsidy reduction proposal. This increase approximates 14 the increase I have proposed for LCI-TOD. 15

16

17

Q. Would you please summarize your testimony?

Yes. I recommend and conclude the following:

- 18
- 19 20

A.

21 22

- The BIP cost of service method, though lacking in some respects is

adequate to use in the determination of a fair apportionment of any

authorized rate increase for LG&E and KU. However, certain corrections should be made to the studies submitted by LG&E and KU.

• Based on the BIP cost of service study, as well as four alternative studies, substantial subsidies are being paid by other rate classes to the residential class, for both LG&E and KU. Regardless of the cost study methodology, these substantial subsidies are present in each Company's rates.

- LG&E's and KU's proposed revenue apportionment method does not adequately address the subsidy problem. KIUC is recommending that the Commission adopt a revenue apportionment method that would explicitly reduce the amount of current dollar subsidies paid and received by 25% in this case.
- KIUC generally supports the Company's proposed large commercial and industrial rate design. Any changes in the allocated revenue increase to LG&E's and KU's large commercial and industrial power rates should be applied to the demand charges proposed by the Companies. Thus for example, if the Commission reduces the targeted revenue requirement assignment to KU's rate LCI-TOD by \$1 million, this decrease from the amount of increase proposed by KU should be used to proportionately decrease the proposed LCI-TOD demand charges.
 - LG&E's and KU's proposed curtailable service rider ("CSR") should be modified by : 1) reducing the annual maximum hours of interruption to 175 hours, 2) increasing the required notice period to 1 hour, 3) adjusting the interruptible credit to reflect fuel savings benefits provided by interruptible load during actual interruptions and 4) implementing a buythrough option that would permit CSR customers to continue operating during economic interruptions if they elect to purchase replacement energy at market prices.
 - Each of the cost of service studies that I developed, as well as the Company's study, consistently show that the KU special contract class is paying well in excess of cost. KU's attempt to unilaterally renegotiate the MeadWestvaco contract in this case by negating the economic value of the contract should be rejected. Therefore, each customer in that class should receive the same percentage increase based upon my 25% subsidy reduction proposal.

	II. COST	OF SERVICE STUDY ISSUES	
Q.	Have you reviewed the C	ompany's proposed "base-intermediate-peak" cost	
	allocation methodology?		
A.	Yes. The BIP method is	the class cost allocation method used by LG&E in prior	
	cases and is being propos	sed for use by KU for the first time in this proceeding.	
	Though the Commission has accepted the BIP method in past LG&E proceedings,		
	the Commission has not ac	ccepted the method for KU in prior cases.	
	The basic methodology,	as discussed by Company witness Steven Seelye, first	
	functionalizes the Company's production and transmission demand-related costs		
	into three periods. Under the Company's BIP functionalization, which is used in		
	both the LG&E and KU studies, total system production and transmission demand-		
	related costs are assigned a	as follows:	
		Assignment of	
		Total P&T Costs	
	D	22 500/	
		33.58%	
	геак	20.4370	
		 Q. Have you reviewed the Callocation methodology? A. Yes. The BIP method is cases and is being propose Though the Commission I the Commission has not address the Commission has not address the Comparison has not address the Comparison has the Comparison has the Comparison has not address the Comparison has not address the Comparison has the Comparison has the Comparison has the LG&E and KU set the LG&E an	

These functional allocators for the base, intermediate and peak periods are identical 1 for both LG&E and KU under the Company's methodology. Once the total 2 production and transmission demand-related costs have been functionalized to these 3 three categories, they are allocated to rate classes using three different class 4 allocation factors. For the 33.58% of production and transmission demand-related 5 costs that are assigned to the base period, costs are allocated using class energy use. 6 For the intermediate period costs that comprise 39.97% of all production and 7 transmission demand-related costs, costs are allocated to classes based on class 8 contribution to the winter system peak demand. Finally, for peak period costs that 9 comprise 26.45% of the Company's total production and transmission demand-10 related costs under the BIP method, costs are assigned based on each customer 11 classes' contribution to the summer coincident peak. 12

13

Under the BIP method, 33.6% of the costs are assigned based on class energy and 40% of the costs are assigned on the basis of contribution to winter peak. Only 26% of the total production and transmission demand-related costs for either of the two operating companies are assigned based on customer class contributions to the summer peak.

19

1		This is somewhat ironic, since it is the summer peak that drives the Company's
2		planning requirements to acquire new generating capacity. In fact, based on the
3		Company's 2001 integrated resource planning document, the summer peak for the
4		combined Company is expected to exceed the winter peak by about 1000 mWs for
5		each of the years through 2016. Placing this into perspective, the Company needs
6		an additional 1000 mWs of generating capacity to meet the summer peak, relative to
7		the requirements associated with the winter peak. Despite this fact, the Company
8		has allocated 40% of its costs based on customer class contributions to the winter
9		peak while allocating only 26% based on class contributions to the summer peak.
10		
10		
11	Q.	Has the Company provided any information that suggests that its proposed
11 12	Q.	Has the Company provided any information that suggests that its proposed BIP methodology is not consistent with the way the Company actually plans its
	Q.	
12	Q.	BIP methodology is not consistent with the way the Company actually plans its
12 13	Q. A.	BIP methodology is not consistent with the way the Company actually plans its
12 13 14		BIP methodology is not consistent with the way the Company actually plans its production facilities?
12 13 14 15		BIP methodology is not consistent with the way the Company actually plans its production facilities? Yes. In response to supplemental data request 14 of KIUC, the Company discussed
12 13 14 15 16		BIP methodology is not consistent with the way the Company actually plans its production facilities? Yes. In response to supplemental data request 14 of KIUC, the Company discussed an alternative cost of service methodology that it considered, but did not use in this
12 13 14 15 16 17		BIP methodology is not consistent with the way the Company actually plans its production facilities? Yes. In response to supplemental data request 14 of KIUC, the Company discussed an alternative cost of service methodology that it considered, but did not use in this case. This methodology, entitled "Unserved Load Methodology," is described by

1		hours occurred during the summer peak period while 28.57% of the unserved load
2		hours occurred during the winter peak period. Under the unserved load
3		methodology, 71.43% of the Company's production costs would be assigned based
4		on summer peak contributions, while 28.57% would be assigned on winter peak
5		period contributions. This is in contrast to the Company's BIP method that assigns
6		40% of the costs based on the winter peak and only 26% on the summer peak. In its
7		response to KIUC No. 14, the Company contrasts the two cost of service methods as
8		follows:
9		
10		While the unserved load methodology offers a good
11 12 13 14		representation of how the Company's production facilities are planned, the BIP methodology offers a good representation of how the production system is utilized.
12 13		planned, the BIP methodology offers a good representation of
12 13 14 15		planned, the BIP methodology offers a good representation of how the production system is utilized.
12 13 14 15 16		planned, the BIP methodology offers a good representation of how the production system is utilized.The Company goes on to state in its response that it selected the BIP method
12 13 14 15 16 17	Q.	planned, the BIP methodology offers a good representation of how the production system is utilized.The Company goes on to state in its response that it selected the BIP method
12 13 14 15 16 17 18	Q.	 planned, the BIP methodology offers a good representation of how the production system is utilized. The Company goes on to state in its response that it selected the BIP method because it had previously been accepted by the Commission.
12 13 14 15 16 17 18	Q.	 planned, the BIP methodology offers a good representation of how the production system is utilized. The Company goes on to state in its response that it selected the BIP method because it had previously been accepted by the Commission. In its response (referenced above), the Company has identified two alternative
12 13 14 15 16 17 18 19 20	Q.	 planned, the BIP methodology offers a good representation of how the production system is utilized. The Company goes on to state in its response that it selected the BIP method because it had previously been accepted by the Commission. In its response (referenced above), the Company has identified two alternative characteristics of cost allocation methods. One of these characteristics is an

I generally agree with the Company's characterization of the two methodologies. 2 A. The BIP method assigns substantial cost responsibility to customer behavior at the 3 time of the winter peak, even though from a planning perspective, the Company 4 appears to agree that the summer peak is driving its costs. From an economic 5 efficiency standpoint, it would not appear to be particularly rational for rates to be 6 set based on class behavior at the time of the winter peak, when the Company is 7 incurring costs because of customer demand at the time of the summer peak. Under 8 the Company's BIP methodology, even if a customer used no electricity during any 9 peak hour during the summer period, the customer or customer class would be 10 assigned almost 74% of the costs that a similar customer would be assigned who 11 used energy during the summer peak, as well as during the winter and off-peak 12 periods. This would not seem to be an efficient cost allocation method and one that 13 would provide consumers with reasonable price signals related to the costs of 14 providing service. 15

16

The Company has characterized the BIP method as a method that provides a good representation of "how the production system is utilized." Without agreeing or disagreeing with this characterization, I would note that allocating costs based on how the system is utilized is closer to a value of service method for assigning costs

as compared to a cost of service method, which should reflect how costs are actually 1 being incurred to serve customers. 2 3 Are there any indications in the Company's rate design that the summer peak **Q**. 4 is a more significant factor affecting the Company's costs than the winter 5 peak? 6 7 Yes. LG&E's Rate LP-TOD is a good illustration. Under the Company's proposed 8 A. rate design, the peak period demand charge for the summer months is \$9.65 per kW, 9 while the corresponding peak period demand charge for the winter months is \$7.11 10 per kW. This rate design reflects a rational response to the incurrence of costs on 11 the Company's system. Further, it also reflects the fact that market prices during the 12 summer months in the LG&E/KU region are much higher than in the winter and 13 other months of the year. The Company is signaling its customers that summer peak 14 demands for Rate Schedule LP-TOD customers are 36% more costly than winter 15 peak demands while the Company's cost allocation methodology implies the 16 reverse. The BIP method weights contributions to the winter peak significantly 17 more than contributions to the summer peak. 18 19

Q.

2

3

What is your recommendation with regard to the use of the Company's BIP methodology to allocate costs to rate classes in this proceeding?

- Though I do not agree with the underlying methodology associated with the BIP 4 A. method, KIUC is willing to utilize this methodology in order to establish a proposal 5 to apportion the Company's authorized revenue increase to rate classes. As I will 6 discuss subsequently, under a variety of cost allocation methodologies, the results all 7 indicate that certain rate classes are substantially underpaying relative to the cost to 8 serve these classes (principally the residential class), while other rate classes are 9 10 substantially overpaying rates, relative to the costs to actually provide service to these customers (large commercial and industrial customers). Under each of these 11 12 alternative allocation methods, similar patterns are produced with respect to relative class rates of return. In each case, the residential class is shown to be receiving 13 substantial subsidies that are paid by other customers, particularly large customers 14 on the LG&E and KU systems. 15
- 16

Q. Before discussing the alternative cost of service studies that you have
developed, would you please discuss the corrections that you indicated you
have made to the Company's BIP method?

20

1	A.	For both the LG&E and KU BIP class cost of service studies, I have made three
2		methodological adjustments to the Company's analysis. These adjustments produce
3		studies that more properly reflect the underlying assumptions relied upon by the
4		Company's in these studies. In addition, I have made two data corrections that I
5		found to be required in the KU BIP study.
6		
7	Q.	Would you please begin your discussion of the common adjustments that you
8		have made to the LG&E and KU BIP cost of service studies?
9		
10	A.	The first adjustment that I made involves the removal of the ECR related rate base
11		from each of the studies. As discussed by the Company in its testimony and data
12		responses, the Company removed ECR related costs and revenues from each of the
13		class cost of service studies, since these costs are being recovered in the ECR rider.
14		With regard to the investment costs associated with the ECR rider, the Company
15		adjusted its capitalization by removing the associated amounts that are being
16		recovered through the ECR. However, the Company did not make any
17		corresponding adjustments to the rate base of each of the Operating Companies. All
18		of the ECR related investments continue to be included in the Company's rate base
19		and only the capitalization, which affects the required rate of return at proposed
20		rates, has been adjusted. Since these ECR rate base items are not uniform among

·

the customer classes, it is appropriate to also remove these investments from rate
base to produce a consistent cost of service study. These ECR rate base adjustments
are based on the corresponding adjustments that the Company made to its
capitalization.

5

6 The second adjustment that I made concerns the treatment of the curtailable service rider ("CSR") credit in the Company's cost of service study. The methodology used 7 by the Company to reflect interruptible and curtailable credits paid to certain of its 8 9 customers is to reduce the expenses associated with these credit payments for rate classes containing customers taking service under the CSR and then allocating this 10 credit cost as a expense to all rate classes. This methodology, which I generally 11 support, is consistent with the Company's underlying economic rational for setting 12 the interruptible credit. The Company is using the avoided cost associated with a 13 combustion turbine to set the CSR credit level. Since the CSR credits paid to 14 customers are essentially payments for combustion turbine capacity, the Company 15 16 reasonably treated this cost as an expense that is assignable to all customer classes. 17 For cost of service purposes, the Company credits this expense to the customer 18 classes actually providing the interruptible credits and allocates the total to all 19 customer classes (including the aforementioned classes that provide the credits).

20

1	In this case, the Company is proposing to increase the CSR credit. However, the
2	Company has not included the increased "expense" associated with this credit in its
3	present rate cost of service study, although it has reflected this amount in the
4	proposed rate analysis. A proper cost of service study would reflect a proformed
5	level of CSR expenses and expense credits at the proposed CSR credit rate in the
6	cost of service study at "present rates." This would provide a consistent basis to
7	analyze the contribution of each customer class to the Company's overall rate of
8	return. Under the Company's method, there is an unequal level of expenses in
9	present and proposed rates that should be adjusted.
10	
10 11	The final common adjustment made to both the LG&E and KU BIP cost of service
	The final common adjustment made to both the LG&E and KU BIP cost of service studies is to change the methodology used to allocate the CSR related expenses to
11	
11 12	studies is to change the methodology used to allocate the CSR related expenses to
11 12 13	studies is to change the methodology used to allocate the CSR related expenses to customer classes. The Company has used the total BIP allocator to assign the CSR
11 12 13 14	studies is to change the methodology used to allocate the CSR related expenses to customer classes. The Company has used the total BIP allocator to assign the CSR credit expenses to customer classes. A more appropriate allocator for these peaking
11 12 13 14 15	studies is to change the methodology used to allocate the CSR related expenses to customer classes. The Company has used the total BIP allocator to assign the CSR credit expenses to customer classes. A more appropriate allocator for these peaking costs would be the summer coincident peak allocator since these costs are associated

Q. Would you please discuss the additional corrections that you made to the KU BIP cost of service study?

3

Based on a review of the KU BIP cost of service study and the accompanying Α. 4 workpapers, two data anomalies were discovered related to incorrect kW demands 5 used to develop the allocation factors. The first problem occurs for the all electric 6 7 schools and Rate 33 classes, wherein the summer and winter peak demands (used to allocate peak and intermediate costs) where inadvertently set to "zero" for these 8 classes. It appears that this was an error in the spreadsheet. The second error 9 concerns the failure to include any NCP kW demand for Rate Schedule HLFS 10 11 secondary load. NCP demand is used to assign costs associated with secondary and primary distribution service. Though the Company did assign demand for HLFS 12 13 primary customers, no HLFS secondary demand was assigned.

14

Q. Have you made these corrections to the Company's filed BIP class cost of service studies?

17

A. Yes. Baron Exhibit ____(SJB-2) contains the corrected KU BIP class cost of
 service study, while Baron Exhibit ____(SJB-7) contains the corrected LG&E BIP
 class cost of service study. Both of these studies reflect the aforementioned changes

1		that I have just discussed. Though, in total, these changes do not have a significant
2		impact on the cost of service study results, I believe they each represent a reasonable
3		adjustment (and in the case of KU, a required correction) to the Company's studies.
4		
5	Q.	Would you please describe the additional studies that you have developed to
6		assess the contributions of each customer class to the Company's overall cost of
7		service
8		
9	А.	Yes. Baron Exhibits(SJB-3),(SJB-4). (SJB-5) and(SJB-6) contain
10		the results of three alternative cost of service studies for KU. Each of these studies
11		incorporates the corrections that I previously discussed with regard to the
12		Company's BIP cost of service study.
13		
14		The first alternate cost of service study utilizes a traditional average and excess
15		demand method ("A&E"). The A&E methodology, which allocates production and
16		transmission demand costs in this study is presented in Exhibit(SJB-3). This
17		traditional cost of service method allocates demand related costs based on each
18		class's contribution to average demands and the class contribution to excess
19		demands, which is defined as the class peak mW in excess of the average demand
20		mW for the class. The calculation of each class's allocation factor is two-fold.

1		First, production and transmission demand costs are assigned into two functional
2		categories in a manner similar to the BIP method. The functional allocator used in
3		the A&E method is the system load factor (about 60% for KU, 51% for LG&E).
4		The costs that are allocated using class contribution to average demand is the
5		amount equal to the system load factor (in percent) times the total production and
6		transmission demand costs. The remaining amount of production and transmission
7		demand related costs [(1 - load factor) times total demand costs] is allocated on
8		each classes' relative excess demand. Excess demand is defined as the class non-
9		coincident peak minus the class average demand.
10		
11	Q.	What is the rationale for the A&E methodology?
11 12	Q.	What is the rationale for the A&E methodology?
	Q. A.	What is the rationale for the A&E methodology? The A&E method recognizes that production and transmission demand costs are
12		
12 13		The A&E method recognizes that production and transmission demand costs are
12 13 14		The A&E method recognizes that production and transmission demand costs are incurred for both an energy and a demand basis. However, unlike the BIP method,
12 13 14 15		The A&E method recognizes that production and transmission demand costs are incurred for both an energy and a demand basis. However, unlike the BIP method, the energy share of costs is equal to the system load factor. For the remaining
12 13 14 15 16		The A&E method recognizes that production and transmission demand costs are incurred for both an energy and a demand basis. However, unlike the BIP method, the energy share of costs is equal to the system load factor. For the remaining amount of costs, however, the allocation is based on each customer classes' excess
12 13 14 15 16 17		The A&E method recognizes that production and transmission demand costs are incurred for both an energy and a demand basis. However, unlike the BIP method, the energy share of costs is equal to the system load factor. For the remaining amount of costs, however, the allocation is based on each customer classes' excess demand. Though this excess demand is based on the class non-coincident peak,

1		component of costs. One of the reasons why the class non-coincident demand is
2		used for the excess portion is that if the class coincident peak demand is used, the
3		A&E method becomes identical to a single coincident peak method.
4		
5	Q.	Would you please discuss the remaining cost of service studies that you have
6		developed for KU?
7		
8	A.	Baron Exhibit(SJB-4) contains the results of a summer/winter average
9		coincident peak cost of service study, while Exhibit(SJB-5) contains the results
10		of a single summer coincident peak study. Exhibit(SJB-6) contains the results
11		of a 12 CP study. Each of these studies represents additional cost of service
12		methodologies that have been used to allocate production and transmission demand
13		costs. In fact, the summer winter average method is similar to the unserved load
14		methodology that I referenced earlier in my testimony except that it is based on an
15		equal weighting between the summer and winter peaks instead of the $73/27\%$
16		weighting that the Company computed using the unserved load method.
17		
18	Q.	What do the studies show with regard to the rate of return paid by the
19		residential class and the all-electric residential class?
20		

As can be seen from each of the exhibits summarizing the studies evaluated, the 1 A. 2 residential and all electric residential classes pay substantially below the average system rate of return. Under each of these methods, the residential class barely 3 covers its cost of service expenses and provides only a small portion of its share of 4 KU's return. In fact, in a number of cases, the all-electric residential class produces 5 a negative rate of return, while the residential class produces a negative rate of 6 return under the summer CP method. Even under the Company's BIP method, 7 which generally favors low load factor classes such as the residential class because 8 of its use of an energy allocator for a substantial part of the costs, the Company's 9 10 residential class is only paying a rate of return on investment of 0.84%, compared to the system average rate of return of 4.27%. This is in contrast to the rate of return 11 12 paid by large commercial and industrial customers on Rate LCI-TOD. These customers are paying rates of return of between 8% and 10%, compared to the 13 system average rate of return of 4.27%. The Company's coal mining rates are 14 paying rates of return even higher than this level. Similar results are shown for the 15 special contracts class that contains large industrial customer load. 16

17

Q. Is there an alternative way to present this cost of service information so that it
could be used to assess the relative contribution of each customer class to the
Company's overall costs?

2	A.	Yes. Table 1 below shows a summary for the five cost of service studies of the
3		relative class rates of return under present rates.

Class		Table 1 entucky Utiliti ern Indices un		Rates		
		Corrected <u>BIP</u>	Average <u>& Excess</u>	Sum/Win <u>CP</u>	Summer <u>CP</u>	12 <u>CP</u>
Total System		1.000	1.000	1.000	1.000	1.000
Residential	Rate RS Rate	0.196	0.119	0.175	(0.025)	0.220
All Electric Residential	FERS	0.113	(0.083)	(0.058)	0.624	0.231
General Service	GS	1.454	0.960	1.361	0.983	1.099
Combined Light & Power	LP,HLF, M	2.120	2.568	2.323	1.878	1.985
Large Comm/Ind TOD	LCI-TOD	1.902	2.444	2.393	2.121	1.768
Coal Mining Power Primary	MPP	3.179	2.874	3.511	3.860	2.726
Coal Mining Power Transmission	MPT	2.848	3.153	3.196	3.612	2.596
Large Power Mine TOD Pri	LMPP	2.370	1.673	2.830	3.216	1.654
Large Power Mine TOD Trans	LMPT	2.405	2.292	2.605	2.999	2.509
Combination Off-Peak	CWH	(3.264)	(3.254)	(3.234)	(3.215)	(3.211)
All Elcetric School	AES	1.084	0.490	1.010	0.515	0.718
Electric Space Heating Rider	33	0.452	(0.021)	0.410	0.018	0.050
Street Lighting	St Lt	(0.128)	(0.190)	(0.122)	(0.004)	(0.052)
Decorative Street Lighting	Dec St Lt	0.769	0.733	0.778	0.854	0.823
Private Outdoor Lighting	PO Lt	2.143	1.932	2.260	3.078	2.726
Customer Outdoor Lighting	COLt	1.643	1.449	1.736	2.447	2.142
Special Contracts		2.060	2.810	1.941	1.347	3.719

3 4 This type of analysis is commonly referred to as a rate of return index presentation.

5

For the total system, the rate of return index is 1.0. For the residential class, under the corrected BIP method, the rate of return index is 0.196. This means that

1		residential customers are paying a rate of return at approximately 20% of the system
2		average. This is in contrast to the rate of return index for the large
3		commercial/industrial time-of-day class that has a rate of return index of 1.9. For
4		this class, customers are paying a return on investment equal to 190% of the system
5		average. A similar result occurs for the special contact class.
6		
7	Q.	What conclusions do you draw from these relative rate of return indices using
8		a variety of cost of service methods?
9		
10	A.	Regardless of the cost of service method, residential and residential all electric
11		customers are paying rates of return substantially below the system average rate of
12		return. Under each method, residential customers are barely contributing any
13		amount to the Company's overall return on investment. At the same time, large
14		industrial customers under Rate Schedule LCI-TOD and special contracts are paying
15		rates of return two or more times the system average rate of return at present rates.
16		The fact that this result occurs under a variety of cost of service methodologies
17		suggests that it is not simply the selection of a cost of service method that is
18		producing these results, but rather it is a clear indicator that substantial subsidies
19		exist in KU rate.
20		

1	Q.	Have you prepared similar analyses for LG&E?
2		
3	A.	Yes. Baron Exhibits (SJB-7), (SJB-8), (SJB-9), (SJB-10) and
4		(SJB-11) contain cost of service study results for LG&E reflecting the same
5		five study methodologies. The corrected BIP method that I previously discussed
6		presented in Exhibit (SJB-7), while Exhibits (SJB-8) through (SJB-11) contain the
7		LG&E A&E results, the summer/winter CP results, the summer CP results.
8		
9	Q.	Do the LG&E cost of service study results, under each of the five methods, lead
10		to similar conclusions with regard to subsidies being paid to residential
11		customers?
12		
13	А.	Yes. As can be seen, the rate of return for residential customers is in the range of
14		1.7% based on the corrected BIP method, compared to an overall system rate of
15		return of 4.59%. For large customers on Rates LP and LP-TOD, the rate of return
16		under the corrected BIP method is 5.82%, while under the four alternative methods
17		the rate of return rises to between 7% and 9%. ¹ Table 2 summarizes these class
18		rates of return using the relative rate of return indices.

These reflect a combined rate of return for LP/LP-TOD rates.

1	

Γ

	Table 2 Louisville Gas & Electric Company Class Rate of Return Indices under Present Rates					
		Corrected	Average	Sum/Win	Summer	12
		BIP	& Excess	<u>CP</u>	<u>CP</u>	<u>CP</u>
Total System		1.000	1.000	1.000	1.000	1.000
Residential	Rate R	0.368	0.367	0.255	0.312	0.509
Water Heating	Rate WH	(1.606)	(1.825)	(1.599)	(1.531)	(1.599)
General Service	Rate GS	2.095	1.558	1.875	1.341	1.630
Rate LC/LC-TOD		1.649	1.778	1.699	1.583	1.350
Rate LP/LP-TOD		1.269	1.529	1.761	2.051	1.274
Street Lighting	Rate PSL	0.705	0.634	0.916	1.508	1.246
Street Lighting	Rate SLE	0.103	(0.301)	0.802	9.501	3.024
Street Lighting	Rate OL	0.790	0.721	0.967	1.434	1.232
Street Lighting	Rate TLE	2.424	3.796	3.422	4.400	2.664
Special Contracts		1.344	1.451	1.758	1.708	1.452

As can be seen, the residential class is producing a relative rate of return of .368 3 4 which means that residential customers are paying a rate of return of about 37% of the system average rate of return. This is in contrast to large power customers who 5 6 are paying a rate of return of approximately 130% of the system average under the BIP method and relative rates of return of 150% to 200% under the alternative 7 8 methods. For special contracts, similar results are also shown. Again, for LG&E as 9 in the case of KU, under a variety of cost of service methods, residential customers 10 are receiving substantial subsidies from other customer classes.

Q. Has KU proposed increases for each of its customer classes to address the subsidy problem that you have just identified?

1

2

3

4

No. Table 3 shows the proposed increases requested by KU in this case. Based on 5 Α. the Company's overall increase request of \$58.9 million, total revenues will increase 6 by 8.7% or 14.2% on a non-fuel basis. For residential customers, the Company is 7 proposing to increase rate revenues by 9% (.3% higher than the system average) or 8 13.7% on a non-fuel basis. Since the increase requested by the Company in this 9 10 case is related to non-fuel costs, it is appropriate to look at the impact of the Company's increase on non-fuel rate revenues. On this basis, despite the fact that 11 12 the residential class is not paying even close to cost of service at present rates, the Company is actually proposing a smaller increase to non-fuel rate revenues for 13 residential customers than the system average increase. The final column of the 14 table shows the rate of return index at proposed rates under the Company's revenue 15 16 apportionment recommendation. As can be seen, the Company is proposing to move the residential class to a rate of return index of 0.493. This means that under 17 18 the Company's proposed rates, residential customers will continue to pay a rate of 19 return on allocated investment at about 44% of the system average rate of return.

Table 3 Kentucky Utilities

KU Proposed Increase

	KU	on Total	on Non-Fuel	ROR Index
	Proposed	Rate	Rate	at Proposed
	Increase	<u>Revenues</u>	<u>Revenues</u>	<u>Rates (1)</u>
Fotal System	58,911,660	8.7%	14.2%	1.000
Residential	10,917,610	9.0%	13.7%	0.439
All Electric Residential	13,171,979	10.0%	15.7%	0.391
General Service	5,663,282	8.6%	1 1 .9%	1.262
Combined Light & Power	18,928,419	8.3%	14.4%	1.813
.arge Comm/Ind TOD Coal Mining Power	6,910,666	8.2%	16.6%	1.702
Primary Coal Mining Power	405,257	8.5%	14.6%	2.529
Frans .arge Power Mine TOD	319,850	8.5%	16.4%	2.333
Pri ₋arge Power Mine TOD	165,746	8.5%	15.6%	2.012
Frans	347,607	8.5%	17.6%	1.995
Combination Off-Peak	96,148	23.2%	45.8%	(1.873)
All Electric School Electric Space Heating	-	0.0%	0.0%	0.684
Rider	129,034	19.3%	31.9%	1.046
Street Lighting Decorative Street	512,748	9.5%	10.8%	0.060
lighting	76,631	9.5%	9.9%	0.666
Private Outdoor Lighting Customer Outdoor	517,636	8.2%	9.8%	1.639
_ighting	72,319	8.1%	9.8%	1.289
Special Contracts	676,728	4.7%	9.7%	1.525

2

Focusing on the large commercial/industrial time of day rate, the Company is proposing an increase in total rate revenues of 8.2% and 16.6% on non-fuel rate revenues, well above the system average increase of 14.2% on non-fuel rate revenues. As can be seen, the proposed rate of return index for these large

1		customers is 1.7 (170% of system average). For special contract customers, the
2		Company is proposing a lower overall revenue increase for the class, on both a total
3		rate revenue and a non-fuel rate revenue basis. However, the rate of return index at
4		proposed rates still continues to be 1.5 (150% of the system average). More
5		importantly, as I will discuss, for one of the special contract customers,
6		MeadWestvaco, the proposed non-fuel increase is 50% above the system average
7		(22% compared to the system average increase of 14.2%).
8		
9	Q.	Is the Company proposing a similar revenue apportionment approach for
10		LG&E?
11		
11 12	A.	Yes. Table 4 shows a similar analysis for the LG&E proposed increases. The
	A.	Yes. Table 4 shows a similar analysis for the LG&E proposed increases. The Company is proposing an overall increase of 11.4% on total rate revenues and 15%
12	A.	
12 13	A.	Company is proposing an overall increase of 11.4% on total rate revenues and 15%
12 13 14	A.	Company is proposing an overall increase of 11.4% on total rate revenues and 15% on non-fuel revenues. For residential customers, with a test year relative rate at
12 13 14 15	A.	Company is proposing an overall increase of 11.4% on total rate revenues and 15% on non-fuel revenues. For residential customers, with a test year relative rate at return of about half that of system average at present rates, customers will receive an
12 13 14 15 16	A.	Company is proposing an overall increase of 11.4% on total rate revenues and 15% on non-fuel revenues. For residential customers, with a test year relative rate at return of about half that of system average at present rates, customers will receive an increase of 12.3% on total revenues and 15.6% on non-fuel rate revenues, almost
12 13 14 15 16 17	A.	Company is proposing an overall increase of 11.4% on total rate revenues and 15% on non-fuel revenues. For residential customers, with a test year relative rate at return of about half that of system average at present rates, customers will receive an increase of 12.3% on total revenues and 15.6% on non-fuel rate revenues, almost about the same as the system average. At proposed rates, the rate of return index for

	Prop	osed Increase o LG&E Propo		nues	
			Percent	Increase	
		LG&E Proposed	on Total Rate	on Non-Fuel Rate	ROR Index at Propose
Total System		<u>Increase</u> 64,260,364	<u>Revenues</u> 11.4%	<u>Revenues</u> 15.0%	<u>Rates (1)</u> 1.000
Residential	Rate R	26,277,410	12.3%	15.6%	0.557
Water Heating	Rate WH	156,774	21.7%	30.1%	(0.770)
General Service	Rate GS	8,974,815	11.0%	13.7%	1.776
Rate LC/LC-TOD		13,708,637	10.6%	14.3%	1.449
Rate LP/LP-TOD		10,638,506	10.8%	15.9%	1.199
Street Lighting	Rate PSL	586,307	12.3%	14.0%	0.690
Street Lighting	Rate SLE	17,030	12.3%	18.4%	0.376
Street Lighting	Rate OL	726,051	12.3%	13.7%	0.739
Street Lighting	Rate TLE	56,796	10.4%	13.8%	2.015
Special Contracts		3,118,038	11.4%	14.9%	1.283

contrasted to the Company's proposal for Rate LP time-of-day customers who are 3 receiving an increase on total rate revenues of 10.8% and non-fuel rate revenues of 4 15.9% (in excess of the system average). Again, the Company is proposing a rate of 5 6 return index for these customers at proposed rates of about 1.2, which means that 7 these customers will continue to pay a rate of return at a level of 120% of the Company's required rate of return. Similar results are shown for special contract 8 9 customers.

10

2

1	Q.	What overall conclusions have you drawn from your analysis of the
2		Company's proposed increases in this case for both KU and LG&E?
3 4	A.	Both LG&E and KU have failed to adequately address the subsidy problem in their
5		recommended apportionment of the overall revenue increases in this case. Even
6		under the BIP cost of service study methodology advocated by the Company as the
7		basis to measure the relationship between rates and cost of service, there is no
8		material mitigation n in the subsidy problem under the Companies' proposals.
9		
10	Q.	Have you developed an alternative methodology to apportion the Company's
11		authorized revenue requirement increase in this case?
12		
13	A.	Yes. I am recommending a methodology that would specifically provide for
14		mitigation of the subsidies under present rates paid and received by each rate class.
15		The methodology that I recommend is a "25% subsidy reduction method," wherein
16		the subsidies paid and received by each rate class at present rates are reduced by
17		25% in the apportionment of the authorized revenue requirement increase, if any.
18		
19		Though the alternative cost of service methods that I have looked at (A&E, S/W
20		average, and summer CP and 12 CP) generally produced more favorable results to
21		large industrial and commercial customers, I am relying on the Company's BIP

1		methodology as corrected, to apportion the revenue increase. Under a 25% subsidy
2		reduction methodology, the proposed increases for each customer class are
3		specifically designed to mitigate 25% of the subsidy at proposed rates. Baron
4		Exhibits (SJB-12) and (SJB-13) present the results of the 25% subsidy
5		reduction methodology for KU and LG&E respectively.
6		
7	Q.	Would you please explain the revenue requirement methodology that you are
8		recommending in Exhibits (SJB-12) and (SJB-13)?
9		
10	A.	The methodologies are identical for both Companies and for the purposes of
11		explaining the approach, I will refer to the KU analysis presented in Exhibit (SJB-
12		12). Pages 1 through 3 of Exhibit (SJB-12) contain the results for each KU rate
13		class or rate group (a group of rate schedules with related rate design objectives). ²
14		To simplify the explanation of Exhibit (SJB-12), I will focus on the large
15		commercial/industrial TOD rate schedule. The first set of rows in the exhibit shows
16		the rate of return at present rates under the Company's BIP cost of service study,
17		corrected for the problems that I previously addressed. As shown, for the LCI-TOD
18		rate, the rate of return at present rates is 8.12%, compared to the system average rate
19		of return of 4.27%.

~

² Following the approach of the Company, certain rate classes have been grouped together for the purposes of assigning a revenue increase target for the class or rate schedule. As discussed by the Company in data responses, certain rate schedules have been grouped together by the Company to insure that there is no incentive or disincentive for customers switching due to a change in the relative rates among these schedules.

2	The second set of rows develops the rate of return at KU's proposed rate increase
3	for each customer class or rate grouping. For the LCI-TOD rate, the Company's is
4	proposing an increase of \$6.9 million that would produce a rate of return at
5	proposed rates to 11.51%. This compares to an overall KU rate of return for all rate
6	classes at proposed rates of 6.76%. As I show in Table 3, the rate of return index at
7	proposed rates recommended by KU in this case for the large commercial and
8	industrial TOD rate is 1.7 (the ratio of 11.51% to 6.76%). Despite the Company's
9	proposal to assign a slightly lower overall revenue increase for this class (8.2%) than
10	the system average increase (8.7%), the Company's proposal does very little to
11	reduce the subsidies paid by LCI-TOD customers. Again, it is important to
12	remember that this subsidy analysis is premised on the Company's recommended
13	cost allocation methodology in this case, the BIP method.
14	
15	The next portion of Exhibit (SJB-12) is designed to calculate the increase that would
16	be appropriate if current subsidies (at present rates) are reduced by 25%, after the
17	proposed rate increase. As can be seen for the LCI-TOD class, the subsidy that KU
18	is recommending at proposed rates for these customers is \$9.67 million. This
19	compares to the current subsidy of \$7.8 million. KU is proposing to actually

increase the subsidy paid by LCI-TOD customers by 23%. Ironically, the Company

1

20

KIUC recommends adopting this general approach.

1	is also proposing to increase the subsidies received by residential customers by
2	almost \$2 million and the subsidies received by "all electric residential" customers
3	by an additional \$2 million. Despite the Company's proposal in this case to increase
4	residential rates by approximately 1% above the system average as recognition of
5	the large subsidies being received by these rate schedules, the Company's increase
6	recommendation actually moves subsidies in the opposite direction. Subsidies are
7	increased for residential customers on Rate RS and Rate FERS.
8	
9	Continuing with the discussion of the 25% subsidy reduction methodology, the base
10	rate increase required for a 25% subsidy reduction is computed and shown to be
11	\$3.122 million for Rate LCI-TOD. This produces a rate of return at proposed rates
12	for this rate class of 9.65%, reflecting a 25% subsidy reduction. As can be seen in
13	the fourth set of rows (bottom portion of the exhibit), the amount of subsidies after
14	the increase under KIUC methodology for LCI-TOD would be \$5.8 million, which
15	is a 25% reduction from the current subsidy of \$7.8 million.
16	
17	The final three rows of the exhibit summarize the results of the analysis. The
18	Company is proposing an overall increase of 8.7% on total rate revenues. For Rate
19	Schedule LCI-TOD, KU is proposing an 8.21% increase. This contrasts with a
20	3.27% reduction that would be required if the Company were to achieve equalized

rates of return at proposed rates. Since the KIUC recommended apportionment 1 method only reduces subsidies by 25% (as opposed to 100% that would be required 2 for equalized rates of return), KIUC is proposing an increase for LCI-TOD of 3 3.71%, assuming that the Company received its entire revenue requirement request 4 in this case. For residential customers, the Company is proposing a 9.01% increase, 5 while a 25% subsidy reduction methodology produces a 14.4% increase for Rate RS 6 customers. However, it is important to recognize that these percent increases are 7 premised on the Company receiving its entire \$59 million revenue increase request 8 in this case. To the extent that the Company receives an amount less than its 9 request, as recommended by other KIUC witnesses in this case, the 25% subsidy 10 reduction revenue apportionment methodology would produce lower increases for 11 12 each customer class.

14Table 5 shows the allocation of the increase using the KIUC proposed methodology,15based on the Company's \$58.9 million revenue increase request. The column16labeled "Allocation of Increase" shows the apportionment of the \$58.91 million17increase to each rate class using the 25% subsidy methodology. KIUC recommends18using this allocation apportionment (the percentages shown on Table 5) for any19increase granted KU in this case. Finally, in the event that KU receives a revenue20decrease in this proceeding, KIUC would recommend following the 25% subsidy

13

reduction method, with the caveat that no rate class or group of rate classes should
 receive an increase.

KIUC Propo		Table 5 tucky Utilities using "25% Subsid	dy Reduction" (1)
(As	suming 100%	of KU Requested	Increase)	
		Proposed Inc <u>\$ Amount</u>	rease <u>% Total</u> <u>Rev</u>	Allocation <u>Of</u> Increase
Total System		58,911,660	8.7%	100.000%
Residential	Rate RS	17,484,557	14.4%	29.679%
All Electric Residential	Rate FERS	21,185,839	16.1%	35.962%
General Service	GS	4,905,523	7.5%	8.327%
Combined Lit & Pow	LP,HLF,M	7,857,308	3.5%	13.337%
Large Comm/Ind TOD	LCI-TOD	3,122,526	3.7%	5.300%
Coal Mining Pow Pri	MPP	23,193	0.5%	0.039%
Coal Mining Pow Trans	MPT	48,456	1.3%	0.082%
Lg Pow Mine TOD Pri	LMPP	49,345	2.5%	0.084%
Lg Pow Mine TOD Trns	LMPT	108,077	2.6%	0.183%
Combination Off-Peak	СШН	536,171	129.4%	0.910%
All Elcetric School	AES	328,759	8.3%	0.558%
Electric Space Heat	33	77,318	11.6%	0.131%
Street Lighting	St Lt	1,988,224	36.8%	3.375%
Decorative St Lighting	Dec St Lt	171,660	21.3%	0.291%
Private Outdoor Lighting	PO Lt	340,841	5.4%	0.579%
Customer Outdoor Lgt	COL	76,820	8.6%	0.130%
Special Contracts		607,042	4.2%	1.030%

1	Q.	Is the methodology that you are recommending for LG&E, as shown in Exhibit
2		(SJB-13), identical to the method you have just discussed for KU?
3		
4	А.	Yes. Baron Exhibit (SJB-13), pages 1 and 2, presents an identical analysis for
5		LG&E using the corrected BIP cost of service study results that I previously
6		discussed. Table 6 shows the KIUC recommended apportionment of LG&E's
7		\$64.26 million revenue increase.

		Table 6		
	Louisvil	le Gas & Electric Com	pany	
KIUC	Proposed Incre	ase using "25% Subsi	dy Reduction" (1)	
	(Assuming 10	0% of LGE Requested	Increase)	
		Proposed		Allocation
		<u>\$ Amount</u>	<u>% Total</u> <u>Rev</u>	<u>of</u> Increase
Total System		64,260,364	11.4%	100.000%
Residential	Rate R	37,864,144	17.7%	58.923%
Water Heating	Rate WH	477,652	66.1%	0.743%
General Service Rate GS		3,767,827	4.6%	5.863%
Rate LC/LC-TOD		8,926,641	6.9%	13.891%
Rate LP/LP-TOD		8,710,760	8.9%	13.555%
Street Lighting	Rate PSL	999,777	20.9%	1.556%
Street Lighting	Rate SLE	27,656	19.9%	0.043%
Street Lighting	Rate OL	1,222,512	20.7%	1.902%
Street Lighting	Rate TLE	16,316	3.0%	0.025%
Special Contracts		2,247,079	8.2%	3.497%

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In this case, KIUC is only requesting that the Commission recognize that the reduction of subsidies is a reasonable policy objective and that it should be implemented gradually (25% reduction) beginning in this case for both KU and LGE.

6

1		III. RATE DESIGN ISSUES
2		
3	Q.	Have you reviewed the Company's proposed rate design for large commercial
4		and industrial customers on the KU and LG&E systems?
5		
6	А.	Yes. In both cases (LG&E and KU), the proposed rate design results in a reduction
7		in the energy charges of the large customer rates and increases in the demand
8		charges. As a general rate design policy matter, KIUC supports the Company's
9		basic rate design for Rate Schedules LP and LP-TOD in the case of LG&E and LCI-
10		TOD on the KU system. For both Companies, the rate design philosophy
11		recognizes that the Company's cost of service results support lower energy charges
12		and higher demand charges, every thing else being equal.
13		
14	Q.	Under the assumption that the Commission authorizes a lower revenue
15		increase than requested by each of the Companies and/or adopts the KIUC
16		recommendation to reduce subsidies by 25%, the revenue requirement target
17		for each of the large commercial and industrial rates would be reduced,
18		compared to the targets used by the Company. What is your recommendation
19		as to how KU's proposed LCI-TOD and LG&E's proposed LP-TOD and LP
20		rates should be adjusted in the event of a lower revenue requirement target?

2 A. Since KIUC generally supports the Company's proposal to decrease the energy charges of each of the rates and apply any authorized revenue increases to the 3 4 demand charges, KJUC would recommend continuing this policy in the event that the revenue increases required from each of these rate schedules is lower than 5 In order to accomplish this objective, KIUC 6 proposed by the Company. recommends that any adjustment to the target revenue increase required pursuant to 7 the Commission's decision in this proceeding be applied on an equal percentage 8 basis to reduce the demand charges proposed by the Company in its filing. For the 9 energy charges of the respective rates, KIUC recommends the Company's proposed 10 levels. 11

12

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13 14

Q. Do you have any examples of how this rate design methodology would be implemented?

15

A. Yes. Baron Exhibit ____(SJB-14), pages 1 and 2 show the proposed rate design for KU Rate Schedule LCI-TOD, primary and transmission. The methodology recommended by KIUC is to apply the decrease in targeted revenue requirements for the LCI-TOD rate class to the demand charges of both rates, on an equal

3

percentage basis. In addition, KIUC would maintain, on a constant dollar basis, the proposed voltage differential between the primary and transmission rates.

Under the Company's LCI-TOD rate design proposal, this class receives an increase 4 of \$6,910,666 (see Table 3). Under the KIUC methodology of reducing subsidies 5 by 25%, LCI-TOD would receive an increase of \$3,122,526 (assuming KU is 6 authorized all of its requested increase). The KIUC rate design recommendation is 7 to apply the reduced revenue increase target (\$3,788,140) to the Company's 8 proposed LCI-TOD demand charges. Since KIUC wants to maintain the absolute 9 voltage differentials between primary and transmission, as proposed by the 10 Company, the \$3.788 million reduction in the revenue increase target is applied to 11 the demand charges recommended by KU in this case on an across-the-board basis, 12 holding constant the voltage differentials recommended by KU. Page 1 of Exhibit 13 (SJB-14) shows the results of this analysis. As can be seen in columns 7 and 8, 14 15 KIUC is recommending that the customer charge and the energy charge be maintained at the proposed KU levels. All of the revenue adjustment that KIUC is 16 recommending for Rate LCI-TOD is applied to the on- and off-peak demand 17 18 charges.

19

1		Under the Company's proposal, the on-peak demand charge is \$5.52, while the
2		charge under the KIUC adjusted rate is \$4.79. The end result is to produce an
3		increase for the primary portion of LCI-TOD of \$2.4 million as compared to the
4		Company's proposed increase of \$5.38 million.
5		
6		Page 2 of the exhibit shows a similar analysis for Rate LCIT-TOD, which is the
7		transmission voltage portion of Rate Schedule LCI-TOD. This rate design follows
8		the same methodology as shown on page 1 of the exhibit. The end result is that the
9		proposed on-peak and off-peak demand charges for the primary rate code differ
10		from the corresponding charges for the transmission rate code by exactly the same
11		differential as proposed by the Company for Rate LCI-TOD.
12		
12 13	Q.	Have you performed a similar analysis as an illustration for LG&E's Rate
	Q.	Have you performed a similar analysis as an illustration for LG&E's Rate Schedule LP-TOD?
13	Q.	
13 14	Q. A.	
13 14 15		Schedule LP-TOD?
13 14 15 16		Schedule LP-TOD? Yes. In the case of the LP-TOD rate schedule, the Company has indicated in data
13 14 15 16 17		Schedule LP-TOD? Yes. In the case of the LP-TOD rate schedule, the Company has indicated in data responses that its rate design philosophy is to group the LP-TOD and LP schedules

1		reduced revenue requirement target recommended by KIUC, but maintains the
2		Company's basic rate design philosophy. Baron Exhibit(SJB-15) shows the
3		results of this adjusted rate design for Rate Schedules LP and LP-TOD. All of the
4		target revenue requirement change (in the form of a reduction from that proposed by
5		LG&E) has been applied to the demand charges of the rate, while maintaining
6		differentials on a voltage basis and among Rate Schedules LP and LP-TOD.
7		
8	Q.	Each of the Companies is proposing new tariffs or changes in tariffs associated
9		with riders that would be applicable to large commercial and industrial
10		customers. Have you reviewed these proposals for new riders?
10 11		customers. Have you reviewed these proposals for new riders?
	A.	Yes. Both LG&E and KU are proposing three riders that would be applicable to
11	A.	
11 12	A.	Yes. Both LG&E and KU are proposing three riders that would be applicable to
11 12 13	A.	Yes. Both LG&E and KU are proposing three riders that would be applicable to KIUC members, under certain circumstances. The first of these riders is the excess
11 12 13 14	A.	Yes. Both LG&E and KU are proposing three riders that would be applicable to KIUC members, under certain circumstances. The first of these riders is the excess facilities rider that provides a mechanism for customers to pay for contributions in
11 12 13 14 15	A.	Yes. Both LG&E and KU are proposing three riders that would be applicable to KIUC members, under certain circumstances. The first of these riders is the excess facilities rider that provides a mechanism for customers to pay for contributions in aid of construction monthly, rather than in a single payment. For LG&E, the
11 12 13 14 15 16	A.	Yes. Both LG&E and KU are proposing three riders that would be applicable to KIUC members, under certain circumstances. The first of these riders is the excess facilities rider that provides a mechanism for customers to pay for contributions in aid of construction monthly, rather than in a single payment. For LG&E, the Company is proposing to implement an excess facilities rider for new construction

1		proposal for the LG&E rider, as long as the provision regarding applicability is
2		maintained in the tariff.
3		
4		For KU, there is no current excess facilities charge rider. Rather, current customers
5		pay a lease rate associated with contributions in aid of construction. Under the
6		excess facilities rider for KU, which is a new rider, the lease rate would be reduced.
7		KIUC does not object to KU's excess facilities rider.
8		
9	Q.	Would you please discuss the Company's proposed redundant capacity tariff?
10		
11	A.	For both KU and LG&E, the redundant capacity rider is new and, according to the
12		Company, does not have any test year revenues associated with the rider. Based on
13		discovery responses from the Company, no existing customer facilities would be
14		charged under this redundant capacity rider.
15		
16		It appears that the redundant capacity rider is designed to reflect additional costs that
17		the Company incurs on its distribution system associated with redundant distribution
18		feeders that would be paid for through the excess facilities rider. For specifically
19		assigned distribution facilities (e.g., a separate distribution feeder), customers are
20		required to pay for this investment through a contribution in aid of construction,

pursuant to the excess facilities rider. The redundant capacity rider is designed to
recover incremental costs associated with the distribution system that may be
incurred as a result of providing an alternative distribution feeder to a customer
location.

5

6 Though in principle, KIUC does not object to the redundant capacity rider, KIUC 7 recommends a change to the redundant capacity rider, in the event that the Commission approves the tariff. The change that KIUC recommends is: for each 8 9 instance wherein the Company proposes to charge a redundant capacity fee, the Company must provide to the customer an analysis that shows that the Company 10 will in fact require additional distribution facilities (above the customer provided 11 contributions) in order to provide the redundant distribution capacity to the 12 customer. Under the Company's proposal, the Company would simply be able to 13 charge the customer an additional charge (in the form of a reservation charge) for 14 the assumed additional distribution network facilities that are required to provide the 15 16 customer with a redundant service, beyond the customer specific costs paid for 17 through the excess facilities rider. KIUC recommends that the Company be required to demonstrate to the customer that such additional costs are being incurred 18 to provide the so-called redundant capacity. This requirement would provide the 19 customer an opportunity to review and, potentially challenge, the Company's 20

1		redundant capacity charges pursuant to this tariff. KIUC does not believe that this
2		change to the redundant capacity tariff is burdensome and would provide customers,
3		who would otherwise incur these costs, a basis to evaluate whether the Company
4		will actually incur additional distribution costs associated with the customer's
5		specific request for service.
6		
7	Q.	What is the third new rider being proposed by the Company in this case?
8		
9	А.	The third rider being proposed by both LG&E and KU is associated with
10		intermittent and fluctuating loads. Both LG&E and KU have indicated in responses
11		to KIUC data requests that there were no test year revenues on this rider and that
12		each of the Companies does not know what the revenues will be in the future.
13		KIUC does not object to this tariff. However, since the Company has indicated that
14		it does not know what revenues there will be in the future associated with the tariff,
15		KIUC proposes that in no event should this tariff be applied to existing loads and
16		load characteristics for any customer, currently taking service during the test year.
17		Thus, if the Commission approves this tariff, it would not apply to any existing KU
18		or LG&E customer unless the customer changed its load or load characteristics from
19		the level or behavior that occurred during the test year.
20		

Q. Are there any additional rate design issues that you would like to address?

2

6

A. Yes. KIUC believes that the KU and LGE fuel roll-in procedure should be
modified in a manner that recognizes the differential in fuel costs among rate
schedules on the basis of service voltage.

7 In the current case, both KU and LGE have allocated test year fuel expense on the 8 basis of class energy, adjusted for losses. This is the appropriate method to assign cost responsibility for these energy related costs. 9 However, no such loss 10 adjustments are made to rolled-in fuel costs during the roll-in of fuel costs to base 11 rates that occurs periodically for both Companies. KIUC believes that in future fuel roll-in proceedings, the Company be required to roll-in fuel costs into base 12 rates on a voltage differentiated basis, following the concept used by the Company 13 14 in this case to allocate fuel expense to rate schedules.

- 15
- 16

Q.

10

17

- A. No, not at this time.
- 19

18

Is KIUC recommending that the fuel clause itself be voltage differentiated?

IV. INTERRUPTIBLE AND CURTAILABLE SERVICE

2

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6

- Q. Have you reviewed the Company's proposal to change the interruptible and curtailable service riders applicable to large commercial and industrial customers?

Yes. LG&E is proposing to eliminate its current interruptible service rider and

7 A.

8 replace it with a curtailable service rider ("CSR"). The LG&E proposal, in addition 9 to changing the title of the rider, would result in an increase in the current 10 interruptible credit from \$3.30 per kW for primary customers to \$4.05 per kW and 11 an increase for transmission customers in the credit from \$3.30 per kW to \$3.98 per 12 kW. In addition, the maximum annual hours of interruption is being increased from 13 250 hours to 500 hours per year. Finally, the penalty for unauthorized use during an interruption is being increased from \$15.00 per kW of monthly billing demand to 14 15 \$16.00 per kW for each non-compliance request. This \$16.00 per kW noncompliance charge would apply to each request for interruption (in the event the 16 17 customer failed to comply), as compared to the current penalty charge that applied 18 on a monthly basis to billing demand, rather than on each non-compliance event. The Company is also proposing to continue its current 10-minute notice to interrupt 19 20 requirement in the tariff.

2		For KU, the proposed changes in the interruptible tariff are more substantial. KU
3		currently has a curtailable service rider that incorporates two levels of interruption.
4		For those customers electing a 75 or 100-hour maximum annual interruption level,
5		the Company is proposing to increase the primary voltage interruptible credit from
6		\$1.60 per kW to \$4.19 per kW. The transmission credit for these customers would
7		increase from a \$1.55 per kW to \$4.09 per kW. For customers who elect 150 hours
8		or 200 hours of maximum annual curtailment, the primary credit would increase
9		from \$3.20 per kW to \$4.19 per kW, while the transmission voltage credit would
10		increase from \$3.10 per kW to \$4.09 per kW.
11		
12		However, as in the case of LG&E, the proposed KU CSR tariff permits annual
13		interruptions of up to 500 hours per year for both primary and transmission voltage
14		CSR customers. Thus, for these KU customers, the annual maximum hours of
15		interruption would increase by 250% to 500%.
16		
	Q.	What is the basis for the Company's proposed CSR credits, applicable to both
16	Q.	What is the basis for the Company's proposed CSR credits, applicable to both LG&E and KU?

1	А.	The Company is proposing to revise its interruptible and curtailable service rates to
2		reflect a credit based on the avoided cost associated with a simple cycle combustion
3		turbine. The credit for both LG&E and KU is determined based on the cost of a
4		new CT and reflects the Company's view that interruptible load is a substitute for
5		otherwise required peaking capacity.
6		
7	Q.	Do you believe that the Company's proposed CSR tariff is reasonable, based
8		on its avoided CT cost methodology?
9		
10	А.	In part. First, as I will discuss subsequently, I do not believe that the Company's
11		proposed 500 hour maximum potential hours of interruption is reasonable, based on
12		a review of the Company's expected operation of combustion turbines on the
13		LG&E/KU system. Second, the Company's proposed 10 minute notice provision,
14		which appears to reflect the requirement in ECAR for interruptible load to qualify as
15		spinning reserve, is not reasonable in light of the proposed credit that the Company
16		is offering. Combustion turbines, even in a hot-start mode, cannot start-up in 10
17		minutes unless they are already running. Thus, the Company's proposed 10-minute
18		notice requirement is not reasonable.
19		

1		The third concern that I have with the Company's proposal is that it does not offer
2		curtailable service customers the option of electing to "buy-through" an interruption
3		at prevailing market rates, if such power is available. Finally, the interruptible credit
4		should include an additional component to reflect fuel savings provided during
5		actual interruptions.
6		
7	Q.	Would you please discuss the first concern that you have with the Company's
8		CSR tariff, the increase in the maximum annual hours of potential
9		interruption to 500 hours?
10		
11	A.	The Company is proposing to increase the maximum annualized hours of
12		interruptions on the LG&E system by 100% (from 250 hours per year to 500 hours
13		per year), while increasing the KU maximum annual hours of interruption from
14		either 100 or 200 hours to 500 hours. The Company's proposal appears to be based
15		on its expectations for the operating characteristics of combustion turbines on its
16		system.
17		
18	Q.	Have you performed an analysis to determine a reasonable level of annual
19		maximum interruptions that should be reflected in the Company's CSR tariff?
20		

Yes. Baron Exhibit (SJB-16) shows an analysis of the actual and expected 1 A. 2 operation of the Company's combustion turbine capacity (LG&E and KU 3 combined) for the test year and for calendar year 2004, based on projections developed by the Company. As can be seen from this exhibit, during the test year, 4 the Company's combustion turbines ran from 0 hours per year up to 375 hours per 5 6 year. For calendar year 2004, based on production cost simulations prepared by the 7 Company, the Company's CT's ran from a low of 0 hours per year up to 370 hours 8 per year for Brown Unit 6. In order to develop a reasonable estimate of the 9 expectations of the Company's combustion turbine fleet during the test year and the first rate effective calendar year (2004), I developed an analysis that averaged the 10 11 hours of operation of the Company's CTs for the two years, on a mW weighted basis. The results of that analysis, shown in Exhibit (SJB-16), demonstrate that on 12 13 average, the Company's combustion turbine capacity operates at 174 hours per year. 14 In fact, this value is high because I did not include in the calculation any combustion 15 turbine capacity whose output in either the test year or in calendar year 2004 is 16 expected to be 0 hours. If that capacity had been included, the weighted average 17 hours of CT operation would be much lower.

18

1	Q.	Under your proposed methodology for determining the appropriate level of
2		maximum annual hours of interruption, are the Company's larger CTs given
3		more weight in the calculation?
4		
5	А.	Yes. The Company's newer CTs tend to be larger and are weighted at a higher level
6		in the calculation than the Company's smaller combustion turbines. As shown in
7		Exhibit (SJB-16), these larger units also have the lowest heat rates, which tend to
8		drive the operation of these units to a higher level.
9		
10	Q.	What is your recommendation for modifying the Company's proposed CSR
11		tariff with regard to maximum annual hours of interruption?
12		
13	А.	Based on the analysis that I prepared, I am recommending that the maximum annual
14		hours of interruption be set at 175 hours per year, for both LG&E and KU.
15		
16	Q.	The Company's production cost analysis shows that in future years, beyond
17		2004, some of the Company's CTs will operate in the 400 to 600 hour range
18		annually. Does this information justify the Company's 500 hour maximum
19		hours of interruption?
20		

1	A.	No. These projections are based on production cost simulation model that is, in turn,
2		based on assumptions regarding load on the system, natural gas prices, market
3		conditions and other factors. As such, it is reasonable to rely on the test year results
4		and rate effective period, rather than a longer term forecast for setting rates.
5		
6	Q.	You indicated previously that the Company is proposing to utilize a 10-minute
7		notice requirement for interruption in its KU and LG&E tariffs. Do you
8		believe that this is reasonable?
9		
10	А.	No. Though it is necessary for interruptible load to be curtailed within 10 minutes if
11		it is qualify as ECAR operating reserve, the Company's interruptible credit does not
12		provide any compensation to interruptible customers for operating reserve
13		associated benefits. More significantly, the Company's combustion turbine capacity
14		cannot start from a cold start or even a hot start within 10 minutes. If standard
15		combustion turbine capacity is going to provide spinning reserve capability, it must
16		be running to do so.
17		
18		Since the Company's proposed interruptible credit and the philosophy underlying its
19		CSR tariff is to utilize interruptible load as a substitute for combustion turbine
20		capacity, it is only reasonable to provide a notice provision for interruption

1 equivalent to the start-up time constraint underlying the Company's combustion 2 turbines. Also, if the Company were to offer a 10 minute interruption notice option, then it also should provide customers with the economic benefits (in terms of 3 avoided costs) provided by substituting interruptible load for resources that would 4 otherwise be operating to provide operating reserves on the system. For example, if 5 6 the Company were utilizing combustion turbine capacity to satisfy a portion of its 7 spinning reserve requirements, there would be an economic cost associated with 8 doing so since, presumably, this capacity would have to operate at minimum or above in order to qualify for spinning reserve. Alternatively, if the Company were 9 10 to allocate a portion of its committed units to spinning reserve (by not fully loading 11 such units in merit order), then there is also an economic cost.

12

Q. What is your recommendation with regard to the Company's 10-minute notice provision?

15

A. The Company's CSR tariff should be modified to reflect a notice provision commensurate with an average expected start-up time the Company's CTs. It is my understanding that the start-up time for new combustion turbines would be in the range of 30 minutes for a hot start and up to several hours for a cold start. I would recommend that the notice provision be modified to a 1 hour notice.

2 3

4

5

- Q. You indicated previously that the Company has developed its proposed CSR interruptible credit based on the avoided costs associated with a new combustion turbine. Has the Company fully reflected the avoided cost associated with combustion turbine capacity in its interruptible credit calculation?
- 7

6

8 A. Not entirely. Though I do not object to the Company's calculation of the fixed combustion turbine costs that would be avoided by interruptible load, the Company 9 has not recognized the economic benefits provided by interruptible load that are 10 11 associated with fuel savings. Based on the results shown in Exhibit (SJB-16), the mW weighted average heat rate for combustion turbine capacity on the LG&E/KU 12 system is approximately 10,704 Btu per kWh. At a \$5.00 per million Btu cost of 13 14 natural gas, combustion turbines would have operating costs for each hour that they run equal to about 5 cents per kWh. This is substantially greater than the energy 15 16 charge in either the LCI-TOD rate on the KU system or the LP-TOD energy charge for LG&E. Since interruptible load, when actually interrupted, will avoid the 17 18 otherwise applicable operation of a CT (at perhaps 5 cents per kWh), but the customer only saves the energy charge of the otherwise applicable tariff, there is a 19 20 mismatch between the economic benefits provided and the interruptible credit in

1		Rate CSR. I am recommending that the Company's CSR tariff be revised to include
2		an additional credit based on the actual hours of interruption that reflects the fuel
3		savings provided by interruptible customers, relative to the avoided energy charges
4		in their otherwise applicable rates.
5		
6	Q.	Do you have any additional changes to the Company's proposed CSR tariff
7		that you recommend?
8		
9	А.	Yes. The final change that I propose to the Company's CSR tariff is the
10		implementation of a "buy-through" option that would permit customers on Rider
11		CSR to elect a buy-through of the interruption at market-base rates plus a reasonable
12		administrative fee payable to the Company. This option would only be available in
13		the event that the Company elects to interrupt for economic reasons. In the event of
14		a reliability based interruption, it would not be appropriate to offer the customer a
15		buy-through of the interruption.
16		
17		This buy-through provision is essentially a right-of-first refusal that the Company
18		would offer its customers, compared to third party off-system customers for the
19		energy and capacity otherwise available to serve these interruptible customers.
20		Essentially, if LG&E or KU would otherwise have to purchase off-system to serve

1		the interruptible load and chooses to interrupt instead, the customer would be
2		offered the option to specifically pay for these off-system purchases in lieu of
3		interruption. From the standpoint of the Company, there would be no costs, nor
4		would there be a cost to the Company's firm customers. As I indicated, the
5		administrative costs imposed on the Company to actually administer this buy-
6		through provision should reasonably be recoverable from such customers. In the
7		event that the Company might be able to make an additional off-system sale and
8		chooses to interrupt CSR customers, the buy-through provision would amount to the
9		Company making such sale to the customer directly, for which the customer would
10		compensate the Company. Again, neither the Company nor its firm customers
11		would be affected by this provision.
12		
13	Q.	Have you developed an alternative CSR tariff for each of the two operating
14		companies that reflect the changes that you are recommending?
15		
16	А.	Yes. Baron Exhibit(SJB-17), contains the proposed KIUC CSR rider for
17		Kentucky Utilities, in a redline version. Baron Exhibit(SJB-18) shows a
18		corresponding CSR for LG&E, reflecting the KIUC recommended modifications as
19		a redline version.

1		V. SPECIAL CONTRACT ISSUES
2		
3	Q.	Would you please address the concerns that you have identified with KU's
4		proposed increase to special contract customer MeadWestvaco in this case?
5		
6	А.	As shown in KU's Seelye Exhibit 15, page 22 of 31, KU is proposing to increase the
7		MeadWestvaco special contract by 9.53%, an amount that exceeds both the system
8		average increase and the proposed increase for Rate Schedule LCI-TOD, the
9		otherwise most nearly applicable tariff rate for this customer. KU is proposing to
10		increase the LCI-TOD rate by 8.2% on a total revenue basis and 16.6% on a non-
11		fuel rate revenue basis. The proposed increase for MeadWestvaco on a non-fuel
12		rate revenue basis exceeds 22%.
13		
14	Q.	What cost of service evidence have you developed regarding the KU special
15		contract customer class?
16		
17	А.	As discussed earlier, I have performed five cost of service studies. The KU special
18		contract class shows a rate of return index far in excess of unity in all five studies.
19		The results were: 1) Corrected BIP - 2.06; 2) Average and Excess - 2.81; 3)
20		Summer/Winter Peak- 1.941; 4) Summer CP - 1.347; and 5) 12 CP - 3.719.

1	Q.	Why is the Company proposing to increase the MeadWestvaco contract by an
2		amount greater than the system average increase and the increase being
3		proposed for Rate LCI-TOD?
4		
5	А.	It was not specifically addressed in testimony. However, based on KU responses to
6		data requests, it appears that the Company relied on a MeadWestvaco specific cost
7		analysis in determining the proposed increase.
8		
9	.Q.	Do you believe that the proposal by KU to increase the MeadWestvaco special
10		contract by 9.53% is reasonable?
11		
12	A.	No. First of all, the approach that should be used by the Company is to apply the
13		increase to the special contract class as a whole. As the Company and I have both
14		shown, the special contract class is paying rates far in excess of cost. Accordingly,
15		that class should receive a below system average increase. Individual customers
16		within that class should not be singled out for particularized adverse treatment.
17		Second the specific cost analysis performed by KU on the MeadWestvaco contract
18		is incomplete, and thus flawed. A valid cost of service study for a particular special
19		contract must include all aspects of the contractual relationship between the parties.
20		In every contract there are benefits and detriments to each party and a valid cost of

1		service study would attempt to take that into account. For example, under the
2		special contract, MeadWestvaco's self generation options are severely restricted.
3		Because of the substantial steam generation inherent in the paper production
4		process, this limitation is costly to MeadWestvaco and represents a corresponding
5		benefit to KU. Neither KU nor I have attempted to do a complete cost of service
6		analysis that captures such issues That type of complex analysis is ordinarily done
7		only once; when the Commission initially approves the contract.
8		
9	Q.	Does the KU revenue increase proposal effectively negate the value of the
10		Commission approved special contract to MeadWestvaco?
11		
11 12	A.	Yes. The MeadWestvaco special contract represents the results of a bargain
	A.	Yes. The MeadWestvaco special contract represents the results of a bargain between the utility and MeadWestvaco in which mutual consideration was given.
12	A.	
12 13	A.	between the utility and MeadWestvaco in which mutual consideration was given.
12 13 14	A.	between the utility and MeadWestvaco in which mutual consideration was given. The MeadWestvaco special contract is the only rate option available to this
12 13 14 15	A.	between the utility and MeadWestvaco in which mutual consideration was given. The MeadWestvaco special contract is the only rate option available to this customer since its plant load exceeds the 50 mw limit contained in the standard
12 13 14 15 16	A.	between the utility and MeadWestvaco in which mutual consideration was given. The MeadWestvaco special contract is the only rate option available to this customer since its plant load exceeds the 50 mw limit contained in the standard
12 13 14 15 16 17	A.	between the utility and MeadWestvaco in which mutual consideration was given. The MeadWestvaco special contract is the only rate option available to this customer since its plant load exceeds the 50 mw limit contained in the standard tariff that is otherwise most applicable - LCI-TOD.

1		contract was negotiated. If this were the standard applicable to setting the special
2		contract rate, the Company could propose any cost of service study that might
3		allocate substantial costs to MeadWestvaco and result in a contract rate exceeding
4		the most nearly comparable tariff rate. By proposing an increase to the
5		MeadWestvaco special contract rate in excess of the LCI-TOD rate, the Company
6		has attempted to unilaterally diminish the value of the contract. This is all the more
7		burdensome because of MeadWestvaco's limited options since its load is too large
8		for LCI-TOD, as that rate is currently structured. Therefore, the percentage increase
9		to the MeadWestvaco contract should approximate the percentage increase
10		approved for the otherwise most nearly applicable tariff rate; which in this case is
11		LCI-TOD.
12		
13	Q.	Should the LCI-TOD rate be modified to permit a customer whose demands
14		exceed 50 mW to take service under the rate?
15		
16	А.	Yes. Though MeadWestvaco does not desire to shift its special contract load to
17		LCI-TOD, there is no valid reason why such an option should not be available.
18		KIUC proposes that the LCI-TOD demand limits be increased to 75 mW, which
19		would permit MeadWestvaco to take service under this rate, at its option.
20		

J. Kennedy and Associates, Inc.

1	Q.	Would you summarize your recommendation regarding the appropriate
2		increase for the MeadWestvaco contract?
3		
4	А.	Each contract in the special contract rate class should receive the same percentage
5		increase and that increase should be well below system average based upon the class
6		cost studies and my 25% subsidy reduction proposal. This proposal results in the
7		special contract class and the otherwise most nearly applicable tariff, LCI-TOD,
8		getting nearly the same increase,
9		
10	Q.	Does that complete your testimony?
11		·
12	A.	Yes.

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

IN THE MATTER OF:

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

EXHIBITS	
OF	
STEPHEN J. BARON	

ON BEHALF OF

KENTUCKY INDUSTRIAL USERS COMMITTEE

J. KENNEDY AND ASSOCIATES, INC. ROSWELL, GEORGIA

March 2004

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J. KENNEDY AND ASSOCIATES, INC. ROSWELL, GEORGIA

March 2004

<u>Date</u>	Case	Jurisdict.	Party	Utility	Subject
4/81	203(B)	KY	Louisville Gas & Electric Co.	Louisville Gas & Electric Co.	Cost-of-service.
4/81	ER-81-42	MO	Kansas City Power & Light Co.	Kansas City Power & Light Co.	Forecasting.
6/81	U-1933	AZ	Arizona Corporation Commission	Tucson Electric Co.	Forecasting planning.
2/84	8924	КY	Airco Carbide	Louisville Gas & Electric Co.	Revenue requirements, cost-of-service, forecasting, weather normalization.
3/84	84-038-U	AR	Arkansas Electric Energy Consumers	Arkansas Power & Light Co.	Excess capacity, cost-of- service, rate design.
5/84	830470-EI	FL	Florida Industrial Power Users' Group	Florida Power Corp.	Allocation of fixed costs, load and capacity balance, and reserve margin. Diversification of utility.
10/84	84-199-U	AR	Arkansas Electric Energy Consumers	Arkansas Power and Light Co.	Cost allocation and rate design.
11/84	R-842651	PA	Lehigh Valley Power Committee	Pennsylvania Power & Light Co.	Interruptible rates, excess capacity, and phase-in.
1/85	85-65	ME	Airco Industrial Gases	Central Maine Power Co.	Interruptible rate design.
2/85	I-840381	PA	Philadelphia Area Industrial Energy Users' Group	Philadelphia Electric Co.	Load and energy forecast.
3/85	9243	KY	Alcan Aluminum Corp., et al.	Louisviite Gas & Electric Co.	Economics of completing fossil generating unit.
3/85	3498-U	GA	Attorney General	Georgia Power Co.	Load and energy forecasting, generation planning economics.
3/85	R-842632	PA	West Penn Power Industrial Intervenors	West Penn Power Co.	Generation planning economics, prudence of a pumped storage hydro unit.
5/85	84-249	AR	Arkansas Electric Energy Consumers	Arkansas Power & Light Co.	Cost-of-service, rate design return multipliers.
5/85		City of Santa	Chamber of Commerce	Santa Clara Municipal	Cost-of-service, rate design.

Date	Case	Jurisdict.	Party	Utility	Subject
6/85	84-768- E-42T	Clara WV	West Virginia Industrial Intervenors	Monongahela Power Co.	Generation planning economics, prudence of a pumped storage hydro unit.
6/85	E-7 Sub 391	NC	Carolina Industrials (CIGFUR III)	Duke Power Co.	Cost-of-service, rate design, interruptible rate design.
7/85	29046	NY	Industrial Energy Users Association	Orange and Rockland Utilities	Cost-of-service, rate design.
10/85	85-043-U	AR	Arkansas Gas Consumers	Arkla, Inc.	Regulatory policy, gas cost-of- service, rate design.
10/85	85-63	ME	Airco Industrial Gases	Central Maine Power Co.	Feasibility of interruptible rates, avoided cost.
2/85	ER- 8507698	NJ	Air Products and Chemicals	Jersey Central Power & Light Co.	Rate design.
3/85	R-850220	PA	West Penn Power Industrial Intervenors	West Penn Power Co.	Optimal reserve, prudence, off-system sales guarantee plan.
2/86	R-850220	PA	West Penn Power Industrial Intervenors	West Penn Power Co.	Optimal reserve margins, prudence, off-system sales guarantee plan.
3/86	85-299U	AR	Arkansas Electric Energy Consumers	Arkansas Power & Light Co.	Cost-of-service, rate design, revenue distribution.
3/86	85-726- EL-AIR	ОН	Industrial Electric Consumers Group	Ohio Power Co.	Cost-of-service, rate design, interruptible rates.
5/86	86-081- E-GI	WV	West Virginia Energy Users Group	Monongahela Power Co.	Generation planning economics, prudence of a pumped storage hydro unit.
8/86	E-7 Sub 408	NC	Carolina Industrial Energy Consumers	Duke Power Co.	Cost-of-service, rate design, interruptible rates.
10/86	U-17378	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Excess capacity, economic analysis of purchased power.
12/86	38063	IN	Industrial Energy Consumers	Indiana & Michigan Power Co.	Interruptible rates.

Date	Case	Jurisdict.	Party	Utility	Subject
3/87	EL-86- 53-001 EL-86- 57-001	Federal Energy Regulatory Commission (FERC)	Louisiana Public Service Commission Staff	Gulf States Utilities, Southern Co.	Cost/benefit analysis of unit power sales contract.
4/87	U-17282	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Load forecasting and imprudence damages, River Bend Nuclear unit.
5/87	87-023- E-C	WV	Airco Industrial Gases	Monongahela Power Co.	Interruptible rates.
5/87	87-072- E-G1	WV	West Virginia Energy Users' Group	Monongahela Power Co.	Analyze Mon Power's fuel filing and examine the reasonableness of MP's claims.
5/87	86-524- E-SC	WV	West Virginia Energy Users' Group	Monongahela Power Co.	Economic dispatching of pumped storage hydro unit.
5/87	9781	KY	Kentucky Industrial Energy Consumers	Louisville Gas & Electric Co.	Analysis of impact of 1986 Tax Reform Act.
6/87	3673-U	GA	Georgia Public Service Commission	Georgia Power Co.	Economic prudence, evaluation of Vogtle nuclear unit - load forecasting, planning.
6/87	U-17282	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Phase-in plan for River Bend Nuclear unit.
7/87	85-10-22	СТ	Connecticut Industrial Energy Consumers	Connecticut Light & Power Co.	Methodology for refunding rate moderation fund.
8/87	3673-U	GA	Georgia Public Service Commission	Georgia Power Co.	Test year sales and revenue forecast.
9/87	R-850220	PA	West Penn Power Industrial Intervenors	West Penn Power Co.	Excess capacity, reliability of generating system.
10/87	R-870651	PA	Duquesne Industrial Intervenors	Duquesne Light Co.	Interruptible rate, cost-of- service, revenue allocation, rate design.
10/87	I-860025	PA	Pennsylvania Industrial Intervenors		Proposed rules for cogeneration, avoided cost, rate recovery.

Date	Case	Jurisdict.	Party	Utility	Subject
10/87	E-015/ GR-87-223	MN	Taconite Intervenors	Minnesota Power & Light Co.	Excess capacity, power and cost-of-service, rate design.
10/87	8702-EI	FL	Occidental Chemical Corp.	Florida Power Corp.	Revenue forecasting, weather normalization.
12/87	87-07-01	СТ	Connecticut Industrial Energy Consumers	Connecticut Light Power Co.	Excess capacity, nuclear plant phase-in.
3/88	10064	KY	Kentucky Industrial Energy Consumers	Louisville Gas & Electric Co.	Revenue forecast, weather normalization rate treatment of cancelled plant.
3/88	87-183-TF	AR	Arkansas Electric Consumers	Arkansas Power & Light Co.	Standby/backup electric rates.
5/88	870171C001	I PA	GPU Industrial Intervenors	Metropolitan Edison Co.	Cogeneration deferral mechanism, modification of energy cost recovery (ECR).
6/88	870172C005	5 PA	GPU Industrial Intervenors	Pennsylvania Electric Co.	Cogeneration deferral mechanism, modification of energy cost recovery (ECR).
7/88	88-171- EL-AIR 88-170- EL-AIR Interim Rate	OH Case	Industrial Energy Consumers	Cleveland Electric/ Toledo Edison	Financial analysis/need for interim rate relief.
7/88	Appeal of PSC	19th Judicial Docket U-17282	Louisiana Public Service Commission Circuit Court of Louisiana	Gulf States Utilities	Load forecasting, imprudence damages.
11/88	R-880989	PA	United States Steel	Carnegie Gas	Gas cost-of-service, rate design.
11/88	88-171- EL-AIR 88-170- EL-AIR	ОН	Industrial Energy Consumers	Cleveland Electric/ Toledo Edison. General Rate Case.	Weather normalization of peak loads, excess capacity, regulatory policy.
3/89	870216/283 284/286	PA	Armco Advanced Materials Corp., Allegheny Ludium Corp.	West Penn Power Co.	Calculated avoided capacity, recovery of capacity payments.

Date	Case	Jurisdict.	Party	Utility	Subject
8/89	8555	ТХ	Occidental Chemical Corp.	Houston Lighting & Power Co.	Cost-of-service, rate design.
8/89	3840-U	GA	Georgia Public Service Commission	Georgia Power Co.	Revenue forecasting, weather normalization.
9/89	2087	NM	Attorney General of New Mexico	Public Service Co. of New Mexico	Prudence - Palo Verde Nuclear Units 1, 2 and 3, load fore- casting.
10/89	2262	NM	New Mexico Industrial Energy Consumers	Public Service Co. of New Mexico	Fuel adjustment clause, off- system sales, cost-of-service, rate design, marginal cost.
11/89	38728	IN	Industrial Consumers for Fair Utility Rates	Indiana Michigan Power Co.	Excess capacity, capacity equalization, jurisdictional cost allocation, rate design, interruptible rates.
1/90	U-17282	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Jurisdictional cost allocation, O&M expense analysis.
5/90	890366	PA	GPU Industrial Intervenors	Metropolitan Edison Co.	Non-utility generator cost recovery.
6/90	R-901609	PA	Armco Advanced Materials Corp., Allegheny Ludłum Corp.	West Penn Power Co.	Allocation of QF demand charges in the fuel cost, cost-of- service, rate design.
9/90	8278	MD	Maryland Industrial Group	Baltimore Gas & Electric Co.	Cost-of-service, rate design, revenue allocation.
12/90	U-9346 Rebuttal	МІ	Association of Businesses Advocating Tariff Equity	Consumers Power Co.	Demand-side management, environmental externalities.
12/90	U-17282 Phase IV	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Revenue requirements, jurisdictional allocation.
12/90	90-205	ME	Airco Industrial Gases	Central Maine Power Co.	Investigation into interruptible service and rates.
1/91	90-12-03 Interim	ст	Connecticut Industrial Energy Consumers	Connecticut Light & Power Co.	Interim rate relief, financial analysis, class revenue allocation.

Date	Case	Jurisdict.	Party	Utility	Subject
5/91	90-12-03 Phase II	СТ	Connecticut Industrial Energy Consumers	Connecticut Light & Power Co.	Revenue requirements, cost-of- service, rate design, demand-side management.
8/91	E-7, SUB SUB 487	NC	North Carolina Industrial Energy Consumers	Duke Power Co.	Revenue requirements, cost allocation, rate design, demand- side management.
8/91	8341 Phase I	MD	Westvaco Corp.	Potomac Edison Co.	Cost allocation, rate design, 1990 Clean Air Act Amendments.
8/91	91-372	он	Armco Steel Co., L.P.	Cincinnati Gas &	Economic analysis of
	EL-UNC			Electric Co.	cogeneration, avoid cost rate.
9/91	P-910511 P-910512	PA	Allegheny Ludlum Corp., Armco Advanced Materials Co., The West Penn Power Industrial Users' Group	West Penn Power Co.	Economic analysis of proposed CWIP Rider for 1990 Clean Air Act Amendments expenditures.
9/91	91-231 -E-NC	WV	West Virginia Energy Users' Group	Monongahela Power Co.	Economic analysis of proposed CWIP Rider for 1990 Clean Air Act Amendments expenditures.
10/91	8341 - Phase II	MD	Westvaco Corp.	Potomac Edison Co.	Economic analysis of proposed CWIP Rider for 1990 Clean Air Act Amendments expenditures.
10/91	U-17282	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Results of comprehensive management audit.
	o testimony iled on this.		Utan		
11/91	U-17949 Subdocket A	LA	Louisiana Public Service Commission Staff	South Central Bell Telephone Co. and proposed merger with Southern Bell Telephone Co.	Analysis of South Central Bell's restructuring and
12/91	91-410- EL-AIR	ОН	Armco Steel Co., Air Products & Chemicals, Inc.	Cincinnati Gas & Electric Co.	Rate design, interruptible rates.
12/91	P-880286	PA	Armco Advanced Materials Corp., Allegheny Ludlum Corp.	West Penn Power Co.	Evaluation of appropriate avoided capacity costs - QF projects.

Date	Case	Jurisdict.	Party	Utility	Subject
1/92	C-913424	PA	Duquesne Interruptible Complainants	Duquesne Light Co.	Industrial interruptible rate.
6/92	92-02-19	СТ	Connecticut Industrial Energy Consumers	Yankee Gas Co.	Rate design.
8/92	2437	NM	New Mexico Industrial Intervenors	Public Service Co. of New Mexico	Cost-of-service.
8/92	R-00922314	PA	GPU Industrial Intervenors	Metropolitan Edison Co.	Cost-of-service, rate design, energy cost rate.
9/92	39314	ID	Industrial Consumers for Fair Utility Rates	Indiana Michigan Power Co.	Cost-of-service, rate design, energy cost rate, rate treatment.
10/92	M-00920312 C-007	PA	The GPU Industrial Intervenors	Pennsylvania Electric Co.	Cost-of-service, rate design, energy cost rate, rate treatment.
12/92	U-17949	LA	Louisiana Public Service Commission Staff	South Central Bell Co.	Management audit.
12/92	R-00922378	PA	Armco Advanced Materials Co. The WPP Industrial Intervenors	West Penn Power Co.	Cost-of-service, rate design, energy cost rate, SO ₂ allowance rate treatment.
1/93	8487	MD	The Maryland Industrial Group	Baltimore Gas & Electric Co.	Electric cost-of-service and rate design (flexible rates).
2/93	E002/GR- 92-1185	MN	North Star Steel Co. Praxair, Inc.	Northern States Power Co.	Interruptible rates.
4/93	EC92 21000 ER92-806- 000 (Rebuttał)	Federal Energy Regulatory Commission	Louisiana Public Service Commission Staff	Gulf States Utilities/Entergy agreement.	Merger of GSU into Entergy System; impact on system
7/93	93-0114- E-C	WV	Airco Gases	Monongahela Power Co.	Interruptible rates.
8/93	930759-EG	FL	Florida Industrial Power Users' Group	Generic - Electric Utilities	Cost recovery and allocation of DSM costs.
9/93	M-009 30406	PA	Lehigh Valley Power Committee	Pennsylvania Power & Light Co.	Ratemaking treatment of off-system sales revenues.

Date	Case	Jurisdict.	Party	Utility	Subject
11/93	346	KY	Kentucky Industrial Utility Customers	Generic - Gas Utilities	Allocation of gas pipeline transition costs - FERC Order 636.
12/93	U-17735	LA	Louisiana Public Service Commission Staff	Cajun Electric Power Cooperative	Nuclear plant prudence, forecasting, excess capacity.
4/94	E-015/ GR-94-001	MN	Large Power Intervenors	Minnesota Power Co.	Cost allocation, rate design, rate phase-in plan.
5/94	U-20178	LA	Louisiana Public Service Commission	Louisiana Power & Light Co.	Analysis of least cost integrated resource plan and demand-side management program.
7/94	R-00942986	PA	Armco, Inc.; West Penn Power Industrial Intervenors	West Penn Power Co.	Cost-of-service, allocation of rate increase, rate design, emission allowance sales, and operations and maintenance expense.
7/94	94-0035- E-42T	WV	West Virginia Energy Users Group	Monongahela Power Co.	Cost-of-service, allocation of rate increase, and rate design.
8/94	EC94 13-000	Federal Energy Regulatory Commission	Louisiana Public Service Commission	Gulf States Utilities/Entergy	Analysis of extended reserve shutdown units and violation of system agreement by Entergy.
9/94	R-00943 081 R-00943 081C0001	PA	Lehigh Valley Power Committee	Pennsylvania Public Utility Commission	Analysis of interruptible rate terms and conditions, availability.
9/94	U-17735	LA	Louisiana Public Service Commission	Cajun Electric Power Cooperative	Evaluation of appropriate avoided cost rate.
9/94	U-19904	LA	Louisiana Public Service Commission	Gulf States Utilities	Revenue requirements.
10/94	5258-U	GA	Georgia Public Service Commission	Southern Bell Telephone & Telegraph Co.	Proposals to address competition in telecommunication markets.
11/94	EC94-7-000 ER94-898-00		Louisiana Public Service Commission	El Paso Electric and Central and Southwest	Merger economics, transmission equalization hold harmless proposals.
2/95	941-430EG	со	CF&I Steel, L.P.	Public Service Company of Colorado	Interruptible rates, cost-of-service.

<u>Date</u>	Case	Jurisdict.	Party	Utility	Subject
4/95	R-0094327	1 PA	PP&L Industrial Customer Alliance	Pennsylvania Power & Light Co.	Cost-of-service, allocation of rate increase, rate design, interruptible rates.
6/95	C-00913424 C-00946104		Duquesne Interruptible Complainants	Duquesne Light Co.	Interruptible rates.
8/95	ER95-112 -000	FERC	Louisiana Public Service Commission	Entergy Services, Inc.	Open Access Transmission Tariffs - Wholesale.
10/95	U-21485	LA	Louisiana Public Service Commission	Gulf States Utilities Company	Nuclear decommissioning, revenue requirements, capital structure.
10/95	ER95-1042 -000	FERC	Louisiana Public Service Commission	System Energy Resources, Inc.	Nuclear decommissioning, revenue requirements.
10/95	U-21485	LA	Louisiana Public Service Commission	Gulf States Utilities Co.	Nuclear decommissioning and cost of debt capital, capital structure.
11/95	1-940032	PA	Industrial Energy Consumers of Pennsylvania	State-wide - all utilities	Retail competition issues.
7/96	U-21496	LA	Louisiana Public Service Commission	Central Louisiana Electric Co.	Revenue requirement analysis.
7/96	8725	MD	Maryland Industrial Group	Baltimore Gas & Elec. Co., Potomac Elec. Power Co., Constellation Energy Co.	Ratemaking issues associated with a Merger.
8/96	U-17735	LA	Louisiana Public Service Commission	Cajun Electric Power Cooperative	Revenue requirements.
9/96	U-22092	LA	Louisiana Public Service Commission	Entergy Gulf States, Inc.	Decommissioning, weather normalization, capital structure.
2/97	R-973877	PA	Philadelphia Area Industrial Energy Users Group	PECO Energy Co.	Competitive restructuring policy issues, stranded cost, transition charges.
6/97	Civil Action No. 94-11474	US Bank- ruptcy Court Middle District of Louisiana	Louisiana Public Service Commission	Cajun Electric Power Cooperative	Confirmation of reorganization plan; analysis of rate paths produced by competing plans.

Date	Case	Jurisdict.	Party	Utility	Subject
6/97	R-973953	PA	Philadelphia Area Industrial Energy Users Group	PECO Energy Co.	Retail competition issues, rate unbundling, stranded cost analysis.
6/97	8738	MD	Maryland Industrial Group	Generic	Retail competition issues
7 <i>1</i> 97	R-973954	PA	PP&L Industrial Customer Alliance	Pennsylvania Power & Light Co.	Retail competition issues, rate unbundling, stranded cost analysis.
10/97	97-204	KY	Alcan Aluminum Corp. Southwire Co.	Big River Electric Corp.	Analysis of cost of service issues - Big Rivers Restructuring Plan
10/97	R-974008	PA	Metropolitan Edison Industrial Users	Metropolitan Edison Co.	Retail competition issues, rate unbundling, stranded cost analysis.
10/97	R-974009	PA	Pennsylvania Electric Industrial Customer	Pennsylvania Electric Co.	Retail competition issues, rate unbundling, stranded cost analysis.
11/97	U-22491	LA	Louisiana Public Service Commission	Entergy Gulf States, Inc.	Decommissioning, weather normalization, capital structure.
11/97	P-971265	PA	Philadelphia Area Industrial Energy Users Group	Enron Energy Services Power, Inc./ PECO Energy	Analysis of Retail Restructuring Proposal.
12/97	R-973981	PA	West Penn Power Industrial Intervenors	West Penn Power Co.	Retail competition issues, rate unbundling, stranded cost analysis.
12/97	R-974104	PA	Duquesne Industrial Intervenors	Duquesne Light Co.	Retail competition issues, rate unbundling, stranded cost analysis.
3/98 (Allocate Cost Issu	U-22092 d Stranded ies)	LA	Louisiana Public Service Comission	Gulf States Utilities Co.	Retail competition, stranded cost quantification.
3/98	U-22092		Louisiana Public Service Commission	Gulf States Utilities, Inc.	Stranded cost quantification, restructuring issues.
9/98	U-17735		Louisiana Public Service Commission	Cajun Electric Power Cooperative, Inc.	Revenue requirements analysis, weather normalization.
12/98	8794	MD	Maryland Industrial Group and	Baltimore Gas and Electric Co.	Electric utility restructuring, stranded cost recovery, rate

<u>Date</u>	Case	Jurisdict.	Party	Utility	Subject
			Millennium Inorganic Chemicals Inc.		unbundling.
12/98	U-23358	LA	Louisiana Public Service Commission	Entergy Gulf States, Inc.	Nuclear decommissioning, weather normalization, Entergy System Agreement.
5/99 (Cross- 4 Answeri	EC-98- 0-000 ng Testimony)	FERC	Louisiana Public Service Commission	American Electric Power Co. & Central South West Corp.	Merger issues related to market power mitigation proposals.
5/99 (Respon: Testimo		ΚY	Kentucky Industriał Utility Customers, Inc.	Louisviile Gas & Electric Co.	Performance based regulation, settlement proposal issues, cross-subsidies between electric. gas services.
6/99	98-0452	WV	West Virginia Energy Users Group	Appalachian Power, Monongaheta Power, & Potomac Edison Companies	Electric utility restructuring, stranded cost recovery, rate unbundling.
7/99	99-03-35	СТ	Connecticut Industrial \Energy Consumers	United Illuminating Company	Electric utility restructuring, stranded cost recovery, rate unbundling.
7/99	Adversary Proceeding No. 98-1065	U.S. Bankruptcy Court	Louisiana Public Service Commission	Cajun Electric Power Cooperative	Motion to dissolve preliminary injunction.
7/99	99-03-06	СТ	Соплесticut Industrial Energy Consumers	Connecticut Light & Power Co.	Electric utility restructuring, stranded cost recovery, rate unbundling.
10/99	U-24182	LA	Louisiana Public Service Commission	Entergy Gulf States, Inc.	Nuclear decommissioning, weather normalization, Entergy System Agreement.
12/99	U-17735	LA	Louisiana Public Service Commission	Cajun Electric Power Cooperative, Inc.	Ananlysi of Proposed Contract Rates, Market Rates.
03/00	U-17735	LA	Louisiana Public Service Commission	Cajun Electric Power Cooperative, Inc.	Evaluation of Cooperative Power Contract Elections
03/00	99-1658- EL-ETP	ОН	AK Steel Corporation	Cincinnati Gas & Electric Co.	Electric utility restructuring, stranded cost recovery, rate Unbundling.

Date	Case	Jurisdict.	Party	Utility	Subject
08/00	98-0452 E-GI 98-0452 E-GI	WVA	West Virginia Energy Users Group	Appalachian Power Co. American Electric Co.	Electric utility restructuring rate unbundling.
08/00	00-1050 E-T 00-1051-E-T	WVA	West Virginia Energy Users Group	Mon Power Co. Potomac Edison Co.	Electric utility restructuring rate unbundling.
10/00	SOAH 473- 00-1020 PUC 2234	ТХ	The Dallas-Fort Worth Hospital Council and The Coalition of Independent Colleges And Universities	TXU, Inc.	Electric utility restructuring rate unbundling.
12/00	U-24993	LA	Louisiana Public Service Commission	Entergy Gulf States, Inc.	Nuclear decommissioning, revenue requirements.
12/00	EL00-66- 000 & ER-28 EL95-33-002		Louisiana Public Service Commission	Entergy Services Inc.	Inter-Company System Agreement: Modifications for retail competition, interruptible load.
04/01	U-21453, U-20925, U-22092 (Subdocket I Addressing (LA 3) Contested Issue	Louisiana Public Service Commission	Entergy Gulf States, Inc.	Jurisdictional Business Separation - Texas Restructuring Plan
10/01	14000-U	GA	Georgia Public Service Commission Adversary Staff	Georgia Power Co.	Test year revenue forecast.
11/01	U-25687	LA	Louisiana Public Service Commission	Entergy Gulf States, Inc.	Nuclear decommissioning requirements transmission revenues.
11/01	U-25965	LA	Louisiana Public Service Commission	Generic	Independent Transmission Company ("Transco"). RTO rate design.
03/02	001148-EI	FL	South Florida Hospital and Healthcare Assoc.	Florida Power & Light Company	Retail cost of service, rate design, resource planning and demand side management.
06/02	U-25965	LA	Louisiana Public Service Commission	Entergy Gulf States Entergy Louisiana	RTO Issues
07/02	U-21453	LA	Louisiana Public Service Commission	SWEPCO, AEP	Jurisdictional Business Sep Texas Restructuring Plan.

Date	Case	Jurisdict.	Party	Utility	Subject
08/02	U-25888	LA	Louisiana Public Service Commission	Entergy Louisiana, Inc. Entergy Gulf States, Inc.	Modifications to the Inter- Company System Agreement, Production Cost Equalization.
08/02	EL01- 88-000	FERC	Louisiana Public Service Commission	Entergy Services Inc. and The Entergy Operating Companies	Modifications to the Inter- Company System Agreement, Production Cost Equalization.
11/02	02S-315EG	со	CF&I Steel & Climax Molybdenum Co.	Public Service Co. of Colorado	Fuel Adjustment Clause
01/03	U-17735	LA	Louisiana Public Service Commission	Louisiana Coops	Contract Issues
02/03	02S-594E	со	Cripple Creek and Victor Gold Mining Co.	Aquila, Inc.	Revenue requirements, purchased power.
04/03	U-26527	LA	Louisiana Public Service Commission	Entergy Gulf States, Inc.	Weather normalization, power purchase expenses, System Agreement expenses.
11/03	ER03-753-0	00 FERC	Louisiana Public Service Commission Staff	Entergy Services, Inc. and the Entergy Operating Companies	Proposed modifications to System Agreement Tariff MSS-4.
11/03	ER03-583-0 ER03-583-0 ER03-583-0	01, and	Louisiana Public Service Commission	Entergy Services, Inc., the Entergy Operating Companies, EWO Market-	Evaluation of Wholesale Purchased Power Contracts.
	ER03-681-0 ER03-681-0			Ing, L.P, and Entergy Power, Inc.	
	ER03-682-0 ER03-682-0 ER03-682-0	101, and			
12/03	U-27136	LA	Louisiana Public Service Commission	Entergy Louisiana, Inc.	Evaluation of Wholesale Purchased Power Contracts.
01/04	E-01345- 03-0437	AZ	Kroger Company	Arizona Public Service Co.	Revenue allocation rate design.
02/04	00032071	PA	Duquesne Industrial Intervenors	Duquesne Light Company	Provider of last resort issues.
03/04	03A-436E	со	CF&I Steel, LP and Climax Molybedenum	Public Service Company of Colorado	Purchased Power Adjustment Clause.

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

IN THE MATTER OF:

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

EXHIBIT (SJB-2)

12 Munths Ended September 30, 2003

		:	Allocation		Total	Residential Rate RS	All Electric Residentia ^t Rate FERS	General Service al Secondary GSS		General Service Primary GSP
Description	Ref	Name	Vector	Ì	diate for					
Cost of Service Summary Pro-Forma										
Operating Revenues										
Total Operating Revenue – Actuał				ۍ	768,801,159 \$	137,843,272	2 \$ 147,767,846	ŝ	69,080,018 \$	2,812,620
Pro-Forma Adjustments:					• 000 32-5	AC CC1	a e 129.125	5	1.916 \$	2,528
Eliminate unbilled revenue					COULCIU	(5 723 277)			(2,393,685) \$	(109,346)
Adjustment for Mismatch in fuel cost recovery			Energy		+ 117 828 + 100 mm	181.54		\$	96,991 \$	4,709
Adjustment to Reflect Full Year of FAC Roll-in		FACR!			4 020 011-1	(4.562.37			(2,291,842) \$	(81,531)
Remove ECR revenues		ECRREV			17 ORE 813 5	3.208.16			17,196 \$	66,930
Adjustment to reflect Full Year of ECR Roll-in		ECKK			(776 418) \$	(128,94	9) \$ (192,222)	•	(56,708) \$	(2,269)
Remove off-system ECR revenues					(22,575,669) \$	(3,600,30	*	: *	15,781) \$	(68,780)
Eliminate brokered sales					(4604.742) \$	(915,11	••	•	(42B,633) \$	(15,263)
Eliminate ESM revenues collected			100		1 630 147 \$	295,22	•	•••	19,629 \$	6,105
Eliminate ESM, FAC, ECR from rate retund acct.					12 942 9351 5	(1,508,819)	9) \$ (1,089,604)	\$	12,733) \$	(10,/43)
Eliminate DSM Revenue		DUMMEN			251 167 S	(417.18	- 47	\$	5,724 \$	•
Year end adjustment		TRENU	10 0		(2.564.269) \$	(464,390)	**	\$	(235,213) \$	(8,603)
Merger savings Adjustment for rate switching, increased interruptible credit		RATESW			(3,005,567)	15 547	7 s 16.258	5 5	7,821 \$	304
VDT Amortization and Surcredit			VDIREV		n		•			
					•		* * * * * * * * *		84 774 509 C	2.585.654

304 2,585,654

16,258 \$ 135,772,513 \$

64,724,599 \$

124,345,569 \$

693,449,939 \$

(13,497,703) \$

Total Pro-Forma Operating Revenue

BIP Prod Trans Allocation Corrected Demand Allocation Removes ECR Rafe Base Prestar Revenues Reflect ICSR Inor Allocates CSR Credits on SCP

12 Munths Ended September 30, 2003

		Mameh	Allocation Vector	Comb	Combined Light & Power LPS	Combined Light & Power LPP	Combined Light & Combined Light & Power LPP LPP LPT	Large Commlind TOD Primary LCIP	Large Commlind TOD Transmission LCIT	High Load Factor Secondary HLFS	High Load Factor Primary HLFP	ctor
Description	P		10000	,								
Cost of Service Summary – Pro-Forma												
Operating Revenues												:
⊺otal Operating Revenue Actual				÷	177,000,631	\$ 39,766,392	\$ 602,350	\$ 75,082,958	\$ 21,281,348	\$ 13,981,260	5 26,319,442	244
Pro-Forma Adjustments:								54 A96	\$ 18.376	.,	•	783
Eliminate unbilled revenue			R01	•••	124,451	54,113 6 77,033,4677	31.617)		\$ (1,268,707)	\$ (801,803)	⊊ \$	304)
Adjustment for Mismatch in fuel cost recovery				•	(cc7/01c/0)	4 (10L/Cen'7) 4	, <i>u</i>			•	÷۰	.851
Adjustment to Reflect Fu# Year of FAC Roll-in		FACRI		<i>~</i> •	000,748 15 724 6C7)	••	, .			*		(688)
Remove ECR revenues		ECRREV			(Jen'+e'/c)	• •			*	•	•	, 165
Adjustment to reflect Full Year of ECR Roll-in		ECKRI		. .	467 231	(39.075)		\$ (76,777)	\$	•	•	(26,230)
Remove off-system ECR revenues				÷ •	(F 358 526)				s	••	*7	481)
Eliminate brokered sales			chergy	• ¥	(1 152 341)			••	••		•••	(1968) 200
Eliminate ESM revenues collected		CONINEY	501	ب ر	373.990			\$	\$	•••		770'
Eliminate ESM, FAC, ECK from fate retund acct.		Democry			(98.441)			•	, 	, ,	* · ·	
TILTING COM KOVEDUC		VERNDY			(597.774)	\$ 117,795	••	•••	•7	~		(100,700)
Year and adjustment			R01		(588,297)	\$ (131,879)	\$ (2,000)	\$ (246,535)	\$ (69,809)	5 (46,031)	•	
Merger savings		RATESW		,		\$ (42,856)		\$ (64,186)	••			878 0
Adjustment tof sats switching, indeased interruptions crodi VDT Amortization and Surcradit	_		VDTREV	\$	19,479	5 4,382	\$ 65	\$ 8,140	5 2,334	*io'i \$	•	070
						!			• 18 010 015 •	12 442 305 5	C 22.947.608	7.608

12,452,305 \$ 22,947,608

18,829,635 \$

66,869,408 \$

816,116 \$

35,818,617 \$

159,833,741 \$

(13,497,703) \$

Total Pro-Forma Operating Revenue

BIP Prod Trans Allocation Correted Demand Allocation Removes ECR Rale Base Proston Revenues Refacet CSR Incr Allocates CSR Credits on SCP

12 Munths Ended September 30, 2003

Description	Ref	Name	Allocation Vector	Coal Mining Power Primary MPP	a Coal Mining Power Transmission MPT	ar Large Power Mine Power TOD Primary LMPP		Large Power Mine Power TOD Transmission LMPT	Combination Off- Peak CWH
Cost of Service Summary – Pro-Forma									
Operating Revenues									
Total Operating Revenue Actual				\$ 5,648,629	9 \$ 4,555,273	•	2,206,126 \$	5,430,525	\$ 502,279
Pro-Forma Adjustments:				101		u 10	• PC0 1	4 74R	6E 7
Eliminate unbilled revenue						•••	4 470 UL4	(75 AB3)	(28.144)
Adjustment for Mismatch in fuel cost recovery			Energy	(Z00,U3	•				
Adjustment to Reflect Full Year of FAC Roll-in		FACRI		\$ 12.84	~	36 \$	2,865 \$	11,438	A)1'I
Remove ECR revenues		ECRREV		\$ (182,40)		45) \$	(70,105) \$	(172,666)	(15,723)
Adjustment to reflect Full Year of ECR Roll-in		ECRRI		\$ 132,46	•7	33 \$	51,614 \$	127,076	11,770
Remove off-system ECR revenues			PLPPT	\$ (5,16	*	31) \$	(2,123) \$	(5,583)	5 (637)
Fliminate brokered sales			Energy	\$ (168,612)	2) 5 (147,387)	87) \$	(74,276) \$	(173.926)	\$ (17,704)
Eliminate ESM revenues collected		ESMREV	1	1 (33,08	47	14) 5	(11,418) \$	(28,011)	\$ (2,590)
Eliminate ESM.FAC.ECR from rate refund acct.			R01	\$ 12,01	*	06 \$	4,648 \$	11,466	1,042
		DSMREV			**	~	•••	•	
Year end adjustment		YREND		\$ (234,64	5) \$ (275,257)	57) \$	•	(703,778)	\$ (22,542)
Mercler savings			R01	\$ (18,905)	•	11) 5	(7,311) \$	(18,037)	\$ (1,639)
Adjustment for rate switching, increased interruptible credit		RATESW							
VDT Amortization and Surcredit			VDTREV	\$ 619	\$	493 \$	236 \$	579	\$ 52
Total Pro-Forma Operating Revenue			(13,497,703) \$	3) \$ 4,900,693	3 \$ 3,840,839	-	1,984,106 \$	4,207,348	\$ 427,775

BIP Prod Trans Allocation Corrected Demand Allocators Removes ECR Rate Base Present Revenues Reflect CSR Incr Allocates CSR Credits on SCP

12 Months Ended September 30, 2003

	2		Allocation	All Elce	All Elcetric School And	Electric Space Heating Rider 33	Water Pumping M	St rre t Lighting St Lt	Decorative Street Private Outdoor Lighting Lighting Dec St Lt PO Lt	Private Outdoor Lighting PO Lt	Customer Outdoor Lighting C O Lt	Special Contracts
Description	ž		ACCIO	-								
Cost of Service Summary – Pro-Forma												
Operating Revenues												
Total Operating Revenue Actual				•7	4,464,245	770,054	\$ 818,252	\$ 5,641,223	\$ 817,184	5 6,590,968	\$ 970,465 \$	18,847,769
Pro-Forma Adjustments:						676		5 345 5 345	7 90	5 6.178	\$ 907 \$	16,335
Eliminate unbilled revenue			R01 Energy	~ ~	5,911 5,911 5,913	(37 387)	(37.004)	5 (87,643)	5 (5,009)	(135,957)	s (21,106) \$	(1,007,994)
Adjustment for Mismatch in ruel cost recovery		EACDI	(Rissi)	•	a 719 S	881		\$ (1,021)	•>	(3,573)	5 (2,582) \$	45,827
Adjustment to Reflect Full Year of FAU Routin				ə 44	(143,373) 3	(23.364)	-	\$ (196,772)	*	\$ (227,715)	\$ (33,264) \$	(691,956)
					104 270 5	17.741	5	\$ 144,134	**	\$ 166,721	\$ 24,687 \$	493,/30
			100 Id		(4.931) 5	(846)	~	\$ (1,650)	\$	\$ (2,562)	5 (398) 5	(22,541)
Remove on-system con revenues			Eneruv		(137,125) \$	(23,519)	5	\$ (55,133)		\$ (85,526)	5 (13,277) 5	(634,093)
Cilinitate Store of Sales Eliminate CCM substance collected		FSMRFV	6	- 64	(21,999) 3	1,124	••	\$ (37,564)	•••	5 (43,690)	5 (6,2/9) 5	(133,033)
Eliminate FSM FAC FCR from rate refund acct.			R01	\$	9,445	1,630	••	\$ 12,909	6 7 -	\$ 14,921	2'192 5	
		DSMREV		•1	•	•		•	, ,			•
		VEEND				(19.849)		\$ 16,889	\$ 12,240	\$ 71,430	\$ (16,194) \$	
rtai aujusunen. Memer savints			R01	• ••>	(14,857) 3	(2,564)	\$ (2,722)	\$ (20,307)	\$ (3,001)	\$ (23.470)	5 (3,447) 5	(4CN,U34)
Advision 2011-25 Advisionant for rate switching, increased interruptible credit VDT Amortization and Surcredit		RATESW	VDTREV	•	491	81	\$ 90	\$ 667	\$ 102	\$ 802	\$ 115 \$	2,335
Total Pro-Forma Operating Revenue			(13,497,703) \$	33) \$	4,051,813 \$	684,657	\$ 746,024	\$ 5,421,077	\$ 807,012	\$ 6,328,527	\$ 898,820 \$	14,115,482

BIP Prod Trans Allocation Corrected Demand Allocation Removes ECR Rue Base Present Revenues Reflect CSR Incr Allocates CSR Credits on SCP

12 Months Ended September 30, 2003

		Allocation		Total	Residential	All Electric Residential	Secondary	Primary GSP
Description Ref	Name	Vector		System	N BER			
Operating Expenses								
Construction Individual Examples			-	548,721,322 \$	106,395.052		\$ 44,174,222 \$	1,487,883
Operation and Amortization Expenses				88,376,624	19,523,170	23,225,147	8,505,50U	(25,292)
Regulatory Credits and Accretion Expenses		un't		(8.655,053) 8 711 450	1.794.460	2,152,528	782,026	18,984
Property Taxes				5.761.996	1,259,177	1,510,435	548,750	13,321
Other Taxes Onio Discontion of Allowerses				(246,288)	(39,277)	(45,226)	(16,427)	(UC/) 105 arc
State and Federal Incorne Taxes		TXINCPF		26,916,596 \$	(931,127)	\$ (2,033,485)	5 4,150,131 3	
Specific Assignment of Curtailable Service Rider Credit				(4,582,475)	, 080 820	- 771944	s 449.462 S	11.972
Allocation of Curtaitable Service Rider Credits		SCP	A	* C.+.70C.+			•	
Adjustments to Obersting Expenses.						400 of 1	9 (F0 201) 6	(96.419)
Eliminate mismatch in fuel cost recovery		Energy		(31,644,777) \$	(5,046,623)	(5,810,987)	5 (22.742) 5	(805)
Remove ECR expenses		ECRREV		(246,400) 3 (24.770.742) \$	(3 943 837)		\$ (1,649,456) \$	(75,349)
Eliminate brokered sales expenses		DSMRFV		(2.946.471) \$	(1,510,632)	*	\$ (223,001) \$	(10,756)
Eliminaie USM Expenses Veer and adjustment		YREND		151,410 \$	(251,488)	\$ 1,068,029	\$ 491,740 \$	• •
Depreciation adjustment		DET		••••••••••••••••••••••••••••••••••••••		5 540 587	201.269	4,777
Adjustment for change in depreciation rate		OET		2,091,278 5	247.020	\$ 252,112	\$ 100,391	2,144
Labor adjustment		5		A 010'700'1				
Medical Expense (See Functional Assignment) Automont for neoclophoet ratic henefit (See Functional Assignment)		LBT		, ,	1			
Storm damage adjustment		SDALL		(473,014) \$	(168,017)	(153,325)	(c/c'so) \$	()
Eliminate advertising expenses (See Functional Assignment)		REVUC			- 10 664	• 11 159	5.351	218
Adjustment for amortization of ESM audit expense				352 456 \$	58.340	\$ 74,069	\$ 28,374	956
Amortization of rate case expenses		1BT		*				
Kemove Amortization of one-utility costs (oce numerinal Assignment) Adjustment for injunes and damages account 925 (See Functional Assignment)	anment)	DWD			•			6 105
Adjustment for VDT net savings to shareholders		LBT		2,895,000 \$	713,643	\$ 728,353 • • • • • • •	5 290,030 556 3	40.591
Adjustment for merger savings		LBT		18,968,825 \$	4,6/5,980	 4,772,307 685963) 	(273.150)	(5,834)
Adjustment for merger amortization expenses		LBI Di TOT		5 (010'07/'7) 873 375 3	140.064	208,792	\$ 61,596	5 2,464
Adjustment for MISO schedule 10 expenses				8 434 618 5	1,863,281	\$ 2,216,596	\$ 811,766	19,267
Adjustment for aftect of accounting change		LB1		(601,682) \$	(148,320)	\$ (151,377)	5 (60,278)	(1,288)
Adjustment to remove Alstom experises		PLPPT		(3,126,995) \$	(519.337)	\$ (774,169)	(125,390)	(io) (a)
Adjustment for corporate lease expense		LBT			- 51 BU2	5 73 030	11.043	451
Adjustment for sales tax refund		KU1 DI DDT		5 628 650 F	325,500	• • •	5 143,145	5 ,726
Adjustment for OMU Nox expense		SDALL		(5 277,336) \$	(1,874,536)	5 (J	\$ (774,008)	\$ (6.178)
Adjustment for Ice storm		OMT		163,982 \$	31,796		\$ 13,201	5 442 5 445
Adjustment for management augur rea Adjustment for Retinement of Green River Units 1 & 2		OMPPT		(705,035) \$	(115,317	(135,875)	\$ (49,242)	(2,113) (1661)
		VDTREV		(466,280) \$	(84,947) // 820 466	5	(1,444,794)	(126,962)
Total Expense Adjustments				(35,904,716)	004'070'0)	_		•
Total Operating Expenses	TOE		÷	633,180,928 \$	121,678,365	\$ 133,986,064	\$ 56,525,369	\$ 1,959,223
			**	60,269,011 \$	2,667,204	\$ 1,786,429	\$ 8,199,229	\$ 626,432
							¢ 139 068 150	3,144,534
Net Cost Rate Base			~	1,412,033,543 \$	318,615,663	-0'11° ¢	201-202-201	
	ļ	ļ	ŀ	1 7741	7680	0.48%	5.90%	17.76 BL

Exhibit (SJB-2) Page 5 of 8

BJP Prod Trans Allocation Corrected Demand Allocators Removes ECR Rate Base Present Revenues Reflect CSR Incr Allocates CSR Credits on SCP

12 Months Ended September 30, 2003

Description	, Amerik	Allocation	Comb	Combined Light & Co Power I PS	Compined Light & C Power LPP	Power LPT	TOD Primary 1 LCIP	TOD Transmission LCIT	Secondary HLFS	Primary HLFP
(XDEDSes										
Operation and Maintenance Expenses			**	118,555,031 \$	26,795,526	396,971	\$ 54,387,992	15,141,209 5	9,9/6,981	7 10,000,010 C
Depreciation and Amontization Expenses				15,264,7B0	3,243,751	43,965	0,2/4,319 Jace nec	(000,7 4 0,1	(151,131	100,021,2
Regulatory Credits and Accretion Expenses				(1,664,336)	(H00,004)	(cnc'a)	fenetero)	1000,002)	107,660	201 249
Property Taxes		L AN		400,554,1	300,242	1.1.1	416.043	103 202	75.545	141 217
Other Laxes					120/117	(11)	(946 66)	(207.8)	(5.503)	(10,413)
Calin Uisposition of Allowances		TVINDE		14 DE4 273 4	2 866 184 5	91 969	3.804.648	1.463.006 \$	772,961	5 1,368,681
otate and rederal income taxes Coordin Antionment of Antiothe Condine Didor Andit			•		(181 381)		(271.654)	(489,037)	•	,
Allocation of Curtailable Service Rider Credits		SCP	**	1,097,059 \$	240,238 \$	4,049	441,260	101,228 \$	78,321	\$ 145,724
·										
Adjustments to Operating Expenses:		1	•			(NEO EO)	• /1 010 0E4) •	- /1 110 710) C	(202.002)	(1.337.916)
Eliminate mismatch in fuel cost recovery		Energy	•	(v,511,155) \$	* (658'579'L)	(21,073)		(01.1011)	(101,001)	(8 322)
Remove ECR expenses		ECRREV	A 6	(30,00,00)	<pre>(12,009) \$ (12,009) \$ </pre>	(787,167		(R74 249) 5	(552.511)	S (1.045,554)
Eliminate prokered sales expenses		Demeny	• •	4 (01919) /08 550)	(12 138) \$	(473)				
Vear and adjustment		YREND	+ v1	(360,354) \$	71.010	164,672				s (324,056)
Derrectation adjustment		DET	• •1			. '			•	
Adjustment for change in depreciation rate		DET	•	361,214 \$	76,758 \$	1,041	\$ 148,471	36,626 \$	27,003	50,374
Labor adjustment		LBT	ŵ	179,334 \$	32,574 \$	438	5 63,114 \$	5 16,111 \$	11,823	5 21,(41
Medical Expense (See Functional Assignment)				•					1	
Adjustment for pension/post retir benefit (See Functional Assignment)	ę	LBT				•	101210		(2 245)	(BUU8)
Storm damage adjustment		SDALL		(42,357) 5	\$ (BC9'C)	•	(o)		(~~	(ma)
Eliminate advertising expenses (See Functional Assignment)		REVUC	U 7 4				1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1	1488	1 047	s 1.969
Adjustment for amortization of ESM audit expense		EUX THO	•	76 151 4	3,000 \$	5 12 12	34,935	9.726 5	6,408	\$ 12,076
Amonization of rate case expenses Demove à modifration of one-rifility costs (See Functional À seimment)	th.	a la				.			•	, , 5
Adjustment for injuries and damages account 925 (See Functional Assignment)	assignment)	OMT		, ,		•	,		•	•
Adjustment for VDT net savings to shareholders	/	LBT	- 63	518,096 \$	94,107 \$	1,266	\$ 182,338	\$ 46,544 \$	34,157	5 62,810
Adjustment for merger savings		LBT	57	3,394,708 \$	616,612 \$	8,296	\$ 1,194,727 3	5 304,969 3	223,806	\$ 411,550
Adjustment for merger amortization expenses		LBT	÷	(487,943) \$	(88,630) \$	(1,192)	(171,726)	(43,835) 5 (43,835) 5	(32, 169)	5 (38,133) 6 75,404
Adjustment for MISO schedule 10 expenses		PLTRT	••	181,639 \$	42,444	634	5 83,395 ;	4R4/27	14,034	2014172
Adjustment for effect of accounting change			••	1,456,863	309,562 5	4,196 (nen)	- 010'010 010 10 10 10 10 10 10 10 10 10 10 10		(660 2)	13 054)
Adjustment for it staff reduction		LBT 21222	1 9 4	(10/,5/8) \$	C (RCC'AL)	(207)	(210 and)	5 (5/0°c) 58/	(202)	s (105.639)
Adjustment to remove Alstom expenses		PLP7:	~ ~	t (net cial)		-	(
Adjustment for color tax refind		9 2) <i>U</i> 1	27.620	6.192 \$	94	\$ 11,575	\$ 3,278 \$	2,161	S 4,064
Adjustment for OMU Nor expense		PLPPT	, "	422,118	98,636	1 473	5 193,805	\$ 52,276 \$	34,288	\$ 66,211
Adjustment for ice storm		SDALL		(472.573) \$	(63,098) \$		\$ (108,425) ;		; (25,051)	(33,566)
Adjustment for management audit fee		OMT	••	35,429 \$	8,008	119	\$ 16,254	\$ 4,525 \$	2,982	5 5,618
Adjustment for Retirement of Green River Units 1 & 2		ОМРРТ	•	(164,991) \$	(39,950) \$	(607)	(81,996)	\$ (23,318) 1	(14,958)	5 (28,356) • (45,454)
VDT Amortization and Surcredit		VDTREV	•	(106,432) \$	(23,944) 5	(363)	5 (44,4/8) : /5 111 //7/0)	5 (12,752) 3 (1526,920)	(1,2,0) (9,4,1,1,4) (9,4,1,1,1,4)	(13,434)
Total Expense Adjustments				(neo'coz'e)	(000'000'2)	F2F, 17		(ana'ana')		
Total Operating Expenses	TOE		ŝ	138,112,005 \$	30,699,881 \$	664,784	\$ 59,648,521	\$ 16,237,976	11,054,549	\$ 20,377,504
Net Operating Income (Adjusted)			¢ł	21,721,736 \$	5,118,735 \$	151,332	\$ 7,220,887	\$ 2,591,659	1,437,756	\$ 2,570,104
Net Cost Rate Base			•	239,144,564 \$	50,208,069 \$	672,621	\$ 97,104,812	\$ 23,755,976	17,747,416	\$ 32,944,387
								110 - 110	- 1041	ana -
				2 0 2 4	10.20%	77 50°	7.77			

BIP Prod Trans Allocation Corrected Demand Allocators Removes ECR Rate Base Presen Revenues Refeet CSR Incr Allocates CSR Credits on SCP

Exhibit (SJB-2) Page 6 of 8

12 Months Ended September 30, 2003

		Affocation	Coal	Coal Mining Power Primary	Coal Mining Power Transmission	Large Power Mine Power TOD Primary		Large Power Mine Power TOD Transmission	Combin	Combination Off- Peak
Description Ref	r Name	Vector		МРР	MPT	LMPP		LMPT	D D	CMH
Operating Expenses										
			÷	011 ack c	• J 016 072	* 1 481 354	•	3 476 565 \$		1 174.358
Operation and Amortization Expenses			•	435 106	340.395	-				274,136
Regulatory Credits and Accretion Expenses				(57,578)	(50,518)	(23,673)	(62	(62,245)		(7.097)
Property Taxes		NPT		41,D43	32,334	17,056	56	39.737		24,659
Other Taxes				28,800	22,689	11,96	88	27,883		17,303
Gain Disposition of Allowances				(1.839)	(1,608)	(8)	(810)	(1,897)		(193)
State and Federal Income Taxes		TXINCPF	~	532,175	361,526	159,250	*	360'040 S	_	(8)8'444)
spectric Assignment of Curtanable Service Kider Credit Allocation of Curtailable Service Rider Credits		SCP	ŝ	26,400	\$ 23,067	s 10,168	68 \$	29,038 \$		4,940
Adjustments to Onersting Evenness										
Aujusernents to Operating Expenses. Eliminate mismatch in fuel cost recovery		Energy	••	(236,347)	\$ (206,595)	\$ (104,115)	15) \$	(243,795)		(24,816)
Remove ECR expenses		ECRREV	-	(1,810)	\$ (1,443)	\$ (65	(696) \$	(1,713) \$		(156)
Eliminate brokered sales expenses		Energy		(184,700)	\$ (161,450)	\$ (81,363)	63) \$	(190.521)		(19.393)
Eliminate DSM Expenses		DSMREV	.				•			- 113 580)
Year end adjustment		YREND		(141,450)	5 (165,932)		A 4	(424,230)	• 4	
Lepreciation adjustment Adjustment for sharms in democristion rate			~ ~	10.296	. B 055	s 4.2	9 1 9	269.6		6.487
Acjustment to change in depreciation rate Labor adjustment		LBT	• •1	4,273	3,325	5 1,810	;₽	4,004		4,242
Medical Expense (See Functional Assignment)		2	•	1						
Adjustment for pension/post retir benefit (See Functional Assignment)	~	LBT	••			, ,	••			·
Storm damage adjustment		SDALL	'n	(860)		2	(395) \$			(3,556)
Eliminate advertising expenses (See Functional Assignment)		REVUC	6 7 -	, !			10 e		•	- 16
Adjustment for amortization of ESM audit expense		R01	••	430	244 7 244		B 2	114 0	• •	27.4
Amortization of rate case expenses Demons Americation of one with most /Con Euclided Amiramont	-		∲ 4	717		6 ·	• •			{ .
Kemove Amorizanon of one-utility costs (see Functional Assignment) Adjustment for injuries and demonse execute 025 (See Functional Assignment)	t) seinnmant)		•	, ,			• • •			
Adjustment for VDT net savings to shareholders	fri anni Rice	LBT	• ••	12,344	209'6	5 5,228	28 \$	11,568		12,254
Adjustment for merger savings		LBT	\$	80,880	5 62,948	••	54 \$	15,796		80,293
Adjustment for merger amortization expenses		LBT	\$	(11,625)	\$ (9,048)	~	24) \$	(10,895)		(11,541)
Adjustment for MISO schedule 10 expenses		PLTRT	. " .	5,610	\$ 4,922	\$ 2,306	88	6,064		189 76 467
Adjustment for effect of accounting change			•••	41,526	5 32,48/	5 1/,268		116'85		20, 103 (7,547)
Adjustment for II staff reduction			~ •	(000 00/		* (I.uor)	••	(77.486)		(2 564)
Adjustment to remove Alstom expenses			- -	(000'07)			, ,			-
Adjustment for soles for adjust rease expense Adjustment for soles for adjund		52		888	\$ 709	с, м	343 \$	847		11
Adjustment for CM(1) Nor expense		PLPPT		13,037	\$ 11,438	5,360	60 \$	14.093		1,607
Adjustment for ice storm		SDALL	~	(9,598)		\$ (4,411)	11) 5	,		(39,675)
Adjustment for management audit fee		TMO	ş	1,024	\$ 872	~	443 \$	1,039		351
Adjustment for Retirement of Green River Units 1 & 2		OMPPT	**	(5,092)	5 (4,454)		*	(2'303)		(L) (L)
VDT Amortization and Surcredit Total Expense Adjustments		VDTREV	\$	(3,381) (445,720)	5 (2,696) (435,284)	(1,291) (136,629)	91) \$ 29) \$	(3,165) (738,674)	•	14,263
Total Operating Expenses	TOE		••	3,986,444	3,209,576	\$,699,608	08 \$	3,553,714		1,057,389
Net Oberating Income (Adjusted)			.,	914,249	5 631,263	\$ 284,498	\$ 86	653,634		(629,614)
				<u>-</u>						
Net Cost Rate Base			•	6,738,314	\$ 5,192,612	\$ 2,812,219	\$	6,367,053	•	4,518,731
			$\left \right $	13.57%	12.16%	10.12%	2%	10.27%		-13, 93%

Exhibit (SJB-2) Page 7 of 8

BIP Prod Trans Allocation Corrected Demand Allocators Removes ECR Rute Base Present Revenues Reflect CSR Incr Allocates CSR Credits on SCP

Class Allocation 12 Months Ended September 30, 2003

Description Ref Name Autocation Operation and Maintenance Expenses Propertion Vector Autocation Operation and Maintenance Expenses Propertion Vector Autocation Operation and Maintenance Expenses Propertion Vector Vector Autocation Operation and Maintenance Expenses Propertion NPT Vector Vector Propertion and Amorization Expenses Can Disposition of Allowances NPT Vector Vector Can Disposition of Allowances Can Disposition of Allowances XINCPF Vector Vector Vector Vector Can Disposition of Allowances State and Accaration Expenses TXINCPF Vector Vector <td< th=""><th></th><th>All Elcetric School</th><th>Rider</th><th>Water Pumping 5</th><th>Street Lighting</th><th>Lighting</th><th></th><th>Outdoor Lighting</th><th>Special</th></td<>		All Elcetric School	Rider	Water Pumping 5	Street Lighting	Lighting		Outdoor Lighting	Special
ses errses Expenses Service Rider Credit der Credits ost recovery perciation rate preciation rate frional Assignment) ratic benefit (See Functional Assignment) ratic benefit (See Functional Assignment) of ESM audit expenses taranges account 925 (See Functional Assignment) arranges account 926 (See Functional Assignment)			33		StLt	Dec St Lt		COLt	Contracts
tess entses Cicpenses Service Rider Credit Jer Credits ast recovery perciation rate preciation rate ficual Assignment) preciation rate foroal Assignment) ratic benefit (See Functional Assignment) of ESM audit expense penses and texpenses tration expenses until anage account 925 (See Functional Assignment) anages account 925 (See Functional Assignment) anages account 925 (See Functional Assignment) anages account 925 (See Functional Assignment) and texpenses account 925 (See Functional Assignment) and texpenses account 925 (See Functional Assignment) and texpenses account 925 (See Functional Assignment) account of texpenses account 925 (See Functional Assignment) account of texpenses									
Envice Rider Credit der Credits Service Rider Credit der Credits as recovery penses preciation rate preciation rate filonal Assignment) reif benefit (See Functional Assignment) reif benefit (See Functional Assignment) der Ses Ser exectional Assignment) der Ses Services and expenses der expenses ges fürztion expenses der expenses der expenses der expenses der expenses	J	1 150 511 €	500 705 C	£02.027	3 409 568	PSC PCF	2 024 505	463 DD5 4	12 156 738
Expenses Service Rider Credit der Credits oast recovery perciation rate preciation rate frional Assignment) ratic benefit (See Functional Assignment) ratic benefit (See Functional Assignment) of ESM audit expenses tration expenses tration expenses until o Anage as expenses te expenses	•		93.849	135,562	1.853.401	214,910	932.522	149.201 5	1,733,976
Service Rider Credit der Credits der Credits as i recovery penses preciation rate preciation rate fronal Assignment) retir benefit (See Functional Assignment) retir benefit ses (See Functional Assignment) dimages account 925 (See Functional Assignment) ang to strateholders tratton expenses al 10 expenses until o expenses te oppenses te oppense		(54,972)	(9,429)	(11,457)	(18,394)	(1,051)	(28,558)	(4,433) \$	(251,298)
Service Rider Credit ler Credits ast recovery perciation rate preciation rate preciation rate preciation rate preciation rate service Functional Assignment) ratic benefit set Se Functional Assignment) antages account 925 (See Functional Assignment) as to strateholders se appense	7	47,953	8,730	12,521	165,497	19,146	84,062	13,444 \$	164,462
Service Rider Credit Ler Credits ast recovery perses proclation rate proclation rate ratio benefit (See Functional Assignment) ratio benefit (expense sea (See Functional Assignment) of ESM audit expenses tration expenses tration expenses tration expenses untiling change as expenses se expenses		33,649	6,126	8,786	116,130	13,434	58,987	9,434 \$	115,403
Service Rider Credit der Credits ost recovery penses preciation rate preciation rate rate benefit (Ser Functional Assignment) rate benefit (Ser Functional Assignment) of ESM audit expense tes (See Functional Assignment) of ESM audit expense tatation expenses tatation expenses tatation expenses te oppenses te oppenses		(1,496)	(257)	(254)	(601)	(34)	(833)	(145) \$	(6,918)
centres ruter uneau der Credits contrecturer preciation rate preciation rate preciation rate preciation rate precise functional Assignment) reichen Assignment) deness der schenses den 10 erpenses der 10 erpenses untim change der schenses der change der schenses	UNCPF \$	172,489 \$	5,722 \$	(1,865) \$	(358,755) \$	50,715 \$	814.753	5 94,631 5	1,261,832
ost recovery periess preciation rate filonal Assignment) ratio benetif (See Functional Assignment) ratio benetif (See Functional Assignment) of ESM audit expense tating casts (See Functional Assignment) and to strateholders at 20 expenses a for expenses	ŗ	, 190 JC	- 13 3		•	•	•	•	(3,530,4U3) 161 E76
ast recovery percation rate preciation rate rate benefit (See Functional Assignment) rate benefit (See Functional Assignment) of ESM audi expense ses (See Functional Assignment) of ESM audi expense tarmages account 925 (See Functional Assignment) anages account 925 (See Functional Assignment) and of expenses targe account 926 (See Functional Assignment) account of expenses	•	1 PD7 02	e onc's	¢ r77'b	, ,	•	,	•	22,101
	ergy \$	(192,211) \$	(32,967) \$	(32,629) \$	(77,281) \$	(4,417) \$	(119,883)	5 (18,611) \$	(888,821)
	SREV \$	(1 423) \$	(232) \$	(262) \$	(1,953) \$	(291) \$	(2,260)	(330) S	(6,866)
	ergy \$	(150,209) \$	(25,763) \$	(25,499) \$	(60,394) \$	(3,452) \$	(93,686)	5 (14.544) \$	(694,595)
	INREV S	• •	-		••••	••• , į			•
		۰, مر י	(11,965) \$		10,181 \$	7,379 5	43,060	(11,571) 5	•
		, . , .		· · ·	- 14 - 14 - 14			,	
		* 101 71	127'7		4,0004		22,000 10,720	4 0,031 4	41,032
	•				e 100'ei	• • • • • • • • • •	10,000		
	T		• •	•		,	•		
	ALL \$	(2.563) 5	(552) 5	(1.032) \$	(3.854) \$	(302) 5	(1001)	633) \$	(812)
	NUC \$		•						· ·
	•	338 \$	5 8 \$	2 9	462 \$	68 \$	534	\$ 82 \$	1,412
	AT \$	2,024 \$	379 \$	387 \$	2,189 \$	208 \$	1,879	\$ 297 \$	8,579
	۲ د	.	•	,	•	• • •	'	•	•
	<u>۱</u>		•		•	<i>د</i> م ۱	•	•	,
	•••	14,041	3,122 \$	3,624 \$	57,308	6,482	31,087	4,981 5	45,016
	<u>ب</u>	81,999 5	20,454 \$	23,742 \$	375,496 5	42,475 5	203,690	32,637 \$	300,200
		(13,ZZ4) 5	(2,940) \$	(3,413) \$	(53,972) 5	(6,103) 5	(29,278)	(4,691) 5	(43,150)
			818 9 6 0 2 4		4 26/1	* 701 * 105	791'7	4 14 24 3	24,400 125 ADD
				10217		1 1 2 4 L V	(1979)	(1025)	1025 0)
	Ltd	(19.659) 5	(3.406) \$	(4 139) \$	(6.645) \$	(380) \$	(10.317)	(1602) \$	(90,781)
		5	5		49 	• (ana)	(\$ · · · · · · · · · · · · · · · · · · ·	-
		\$ 969	120 5	128 \$	953 \$	141 \$	1,102	5 162 \$	2,913
Adjustment for OMU Nox expense	5 ždd	12,447 \$	2,135 \$	2,594 \$	4.165 \$	238 \$	6,466	5 1,004 \$	56,898
	ALL \$	(28,599) \$	(6,163) \$	(11,514) \$	(43,003) \$	(3,368) \$	(45,541)	\$ (7,132) \$	(10,180)
	4 1	942 \$	177 5	180 \$	1,019 \$	\$ 16	874	5 138 \$	3,992
een River Units 1 & 2	APPT \$	(4,423) \$	(759)	(775) \$	(1,569) \$	\$ (06)	(2,434)	5 (378) \$	(20,253)
	TREV \$	(2.682) \$	(442) 2	(490) \$	(3,643) \$	(557) \$	(4,383)	(630) \$	(12,760)
		(224, 183)	(46,221)	(31,273)	429,923	64,722	9498,448	(828'1)	(001,111,11)
Total Operating Expenses	*	3,676,265 \$	655,878 \$	720,273 \$	5,595,768 \$	685,056 \$	4,880,294	5 722,198 \$	11,794,204
Net Operating Income (Adjusted)	*	375,547 \$	28,779 \$	25.751 \$	(174,691) \$	121,956 \$	1,448,234	\$ 176,622 \$	2,321,278
Net Cost Rate Base	**	8,113,397 \$	1,490,422 \$	2,176,766 \$	31,905,511 \$	3.716,038 \$	15,836,075	\$ 2,518,660 \$	26,400,496
		4.0374	1.80%	201.1	1466.0-	×.07°C	a. 10 %	N.1A'J	4.67.0

BIP Prod Trans Allocation Corrected Dremand Allocators Removes ECR Rate Bate Present Revenues Reflect CSR fact Allocates CSR Credits on SCP

Exhibit (SJB-2) Page 8 of 8

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

IN THE MATTER OF:

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

EXHIBIT (SJB-3)

12 Moaths Ended September 30, 2003

	10		Allocation		Total Svstem	Residential Rate RS	All Electric Residential Rate FERS	General Service Secondary GSS	Gene	General Service Primary GSP
Description	ē									
Cost of Service Summary – Pro-Forma										
Operating Revenues										
Total Operating Revenue Actual				•	768,801,159 \$	138,098,905	5 \$ 147,748,544	\$ 69,494,810		2,833,889
Pro-Forma Adjustments:			100		675 000	122 243	3 5 125	5 61,916	\$7	2,528
Eliminate unbilled revenue			Enterner		(35 887 728) \$	(5 723 27	\$	•	* ((109,346)
Adjustment for Mismatch in tue: cost recovery					1417623 \$	181.54	69	••	•	4,709
Adjustment to Reflect Full Year of FAC Koll-In					(25 039 979)	(4.562.377)	49	\$	\$ 5	(91,531)
Remove ECR revenues					17 DRE 813 5	3 208 16		\$	*	66,930
Adjustment to reflect Full Year of ECR Roll-m		ECARS:	Tag ig		(776.418) \$	(138.21		•••	s ((3,040)
Remove off-system ECR revenues					(72 575 669) \$	(3,600,30	\$		5	(68,786)
Eliminate brokerad sales		CARPEN	AR Include		(4.604.742) \$	(915,119)	9) \$ (611,110)) \$ (428,633)	*	(15,263)
			601		1630.147 \$	295,220	\$	5	**	6,105
Eliminate ESM, FAC, ECK from rate retund acct.		Dewpey			(2.942.935) 5	(1,508,819)	a) \$ (1.089,604)	•	3) \$	(10,743)
Eliminate DSM Revenue					751 167	(417 181)		.,	49 T	•
Year end adjustment		TREND	100		/7 K64 760) 5	(464 390)	• • 2	*>	\$ (6	(8,603)
Merger savings		14 T T C M	LUI		(4) 005 567)					
Adjustment for rate switching, increased interruptible credit VDT Amortization and Surcredit			VDTREV		85,337 \$	15,547	7 \$ 16,258	1 \$ 7,821	\$ \$	304

2,606,152

135,753,911 \$ 65,124,351 \$

124,591,934 \$

(13,506,972) \$ 693,449,939 \$

Total Pro-Forma Operating Revenue

Avg Excess Prod Trans Allocation All other KJUC Corrections Included

12 Months Ended September 30, 2003

Description	Ref	Name	Allocation Vector	Combined Light & Power LPS	Combined Light & Combined Light & Power LPP LPP LPT	Large Commilind TOD Primary LCIP	Large Commund Large Commund Hi TOD Primary TOD Transmission LCIP LCIP	High Load Factor Secondary HLFS	High Load Factor High Load Factor Secondary Primary HLFS HLFP
Cost of Service Summary — Pro-Forma									

22,783 (1,517,304) 82,851 (838,62,885) 606,165 (22,844) (160,468) 55,022 55,022 (537,561) (86,551) 13,940,078 \$ 26,226,061 22, 857, 613 12,117 (801,803) 5 (801,803) 5 (445,576) 5 (445,578) 5 (12,090) 5 (504,83) 5 (12,090) 5 (12,090) 5 (12,090) 5 (12,090) 5 (99,283) 5 (99,283) 5 (46,031) 5 (46,031) 5 1,514 \$ 12,452,617 \$ 18,376 5 (1,288,771) 5 94,897 5 94,898 721) 5 432,058 5 (19,486) 5 (19,486) 5 (19,486) 5 (19,486) 5 (19,106) 5 44,379 5 44,379 5 (120,793) 21,247,884 \$ 8,797,384 \$ 64,896 5 (4,365,027) 5 (184,737) 5 (2,401,012) 5 (70,55,487 5 (70,55,487 5 (70,55,487 5 (70,55,487 5 (70,554 7 (70,554 5 (56,186) 5 (64,186) 5 (64,186) 5 (8,140 5 8,140 5 74,911,352 \$ 66,704,024 ****** 602,907 \$ * 526 (31,617) 2,524 (19,498) 14,085 (19,498) 14,085 (19,498) (19,49 816,653 ** -----** ** 34,715 : 34,715 : (2,083,467) : 917,556 : (1,290,909) : 917,556 : (1,31,592) : (1,31,924) : (1,31,924) : (1,21,23) : (12,123) : (12,123) : (12,123) : (12,123) : (12,123) : (12,123) : (13,125) : (13, 39,734,620 35,787,997 **** ••• 176,693,980 \$ 154,859 365,749 365,749 5,724,057) 4,133,949 (156,106) (19,479 159,538,209 ** (13,506,972) \$ ** VDTREV R01 Energy PLPPT Energy R01 R01 ESMREV DSMREV YREND RATESW FACRI ECRREV ECRRI Pro-Forma Adjustments: Eliminate in billet reverue Adjustment for Mismatch in fuel cost recovery Adjustment for Mismatch in fuel cost recovery Adjustment for reflect Full Year of ECR Roll-in Remove off-system ECR revenues Adjustment to reflect Full Year of ECR Roll-in Remove off-system ECR revenues Eliminate ESM Facy. ECR trown rate refund acct. Eliminate ESM Facy. Year end adjustment for rate switching, increased interruptible credit VOT Amortization and Succredit Total Operating Revenue – Actual **Operating Revenues**

2,828

Total Pro-Forma Operating Revenue

12 Months Ended September 30, 2003

Passai séras	Ref	a E Z	Allocation Vector	Coal Mining Power Primary MPP	r Coal Mining Power Transmission MPT	Large Power Mine Power TOD Primary LMPP	Large Power Mine Power TOD Transmission LMPT	Combination Off- Peak CWH
Cost of Service Summary – Pro-Forma								
Operating Revenues								
Total Operating Revenue – Actual				\$ 5,657,368	3 \$ 4,549,667	\$ 2,216,400	\$ 5,433,524	\$ 506,788
Pro-Forma Adjustments:			100	t 4 07			•	
Eliminate unbilled revenue			Enermy	12/2 (268 036)	5) 5 (234,296)	\$ (118,074)	\$ (276,483)	\$ (28,144)
Adjustment for Mismatch in fuel cost recovery			(F)-1-1-1	12.84	. 47	s	\$9	•
		FORREV		5 (182,40		*	•	
Kemaye COM levenues A discrimination meaned Full Vann of FOD Boll-in		FCRRI		\$ 132,46	**	5		\$
			PI PPT	\$ (5.48	~	•	•	\$
Remove on-system row revenues			Enerov	\$ (168,61)	• • • •	••	••	~ ~
Climitate Otokarau sates Climitoto ECM: rotanuae collected		ESMREV	(Breat	\$ (33,08)	•	•	**	
Cliningle Comitevenues concrea Filmingle FSM FAC FCR from rate refund acct.			R01	5 12,01	**	•	\$	
Climinate DOM Devenue		DSMREV		, ,		•	,	, n
Cistingue para hover to the second se		YREND		\$ (234,64	•		\$ (703,778)	(22,542)
teal end aguatraria Merner savinds			R01	\$ (18,905)	5) \$ (15,111)	\$ (7,311)	47	•
Adjustment for rate switching, increased interruptible credit VDT Amortization and Surcredit		RATESW	VDTREV	\$ 619	9 \$ 493	\$ 236	\$ 579	\$ 52
Total Pro-Forma Operating Revenue			(13,506,972) \$	2) S 4,909,115	5 \$ 3,835,436	\$ 1,994,007	\$ 4,210,238	\$ 432, 121

Arg Excess Prod Trans Allocation All other KJUC Corrections Included

12 Months Ended September 30, 2003

		Amely	Allocation	All Elcetr Al	All Elcetric School AFS	Electric Space Heating Rider 33	Water Pumping M	Street Lighting St Lt	Decorative Street Private Outdoor Lighting Lighting Dec St Lt PO Lt	Private Outdoor Lighting PO Lt	Customer Outdoor Lighting C O Lt	\$pecial Contracts
nescription	2				ł					2		
Cost of Service Summary – Pro-Forma												
Operating Revenues												
Total Operating Revenue – Actual				••	4,499,169 \$	776,044	\$ 810,389	\$ 5,650,884	\$ 817,736	\$ 6,601,431	\$ 972,090	18,776,639
Pro-Forma Adjustments:			100			676	·	e 5.345	062	5 6.178	\$ 907	16,335
Eliminate unbilled revenue A director at foot Mismotok in first and anot another			Freme	* •	\$ \E83\ 2	(37.387)	\$ (37.004)	\$ (87,643)	\$ (5,009)	\$ (135,957)	••	(1,007,994)
Activity of Mismarch in Tuel Cust recovery A distance to Defend Still Variation Scilling			(Rinni)		5 218 S	1881		\$ (1.021)	(14)	\$ (3,573)	•	45,827
		FCBREV			(143.373) \$	(23.364)		\$ (196,772)	\$ (29,280)	\$ (227,715)	••	(691,956)
Adjustment to reflect Cuil Veen of FCD Doll-jp		IN ACT			104.270 \$	17 741	••	\$ 144,134	\$ 21.362	\$ 166,721	5	483,730
Cujustificiji tu tejevi nur teat ur Edin Montrij Demove off-evelom FCD revenues		5	1dd 1d		(6,197) \$	(1,063)	•••	\$ (2,000)	5 (114)	\$ (2,941)	••	(19,961)
Eliminata hurkarad salas.			Enerov	. ••	(137,125) \$	(23,519)	•	\$ (55,133)	\$ (3.151)	\$ (85,526)	\$ (13,277)	(634,093)
Fliminate FSM revenues miteriad		ESMREV	5		(21,999) \$	1 124	*>	\$ (37,564)	5 (5,964)	\$ (43,690)		(133,593)
Eliminate ESM FAC FCR from rate refund acct			R01		9,445 \$	1,630	5	\$ 12,909	\$ 1,908	\$ 14,921		R44'89
Fliminate DSM Revenue		DSMREV		.,		•		•	•	•	5	
		VREND				(19.849)	, •	\$ 16,889	\$ 12,240	5 71,430	\$ (19,194)	•
Member savings			R01	• • •	(14,857) \$	(2,564)	\$ (2,722)	\$ (20,307)	\$ (3,001)	\$ (23,470)	••	(62,054)
Adjustment for rate switching, increased interruptible credit VDT Amorization and Surcredit		RATESW	VDTREV	**	491 5	81	\$ 90	\$ 667	\$ 102	\$ 802	\$ 115	2,335
Total Pro-Forma Operating Revenue			(13,506,972) \$	2) \$	4,085,470 \$	690,430	\$ 738,418	\$ 5,430,388	\$ 807,544	\$ 6,338,611	\$ 900,385	14,046,931

Avg Excess Prod Trans Allocation All other KUUC Corrections included

12 Months Ended September 30, 2003

		Allocation		Total	Residential Does Do	All Electric Residential Rate FFRS	Secondary GSS	Primary GSP
Description	Name	Vector		aystern	12 8992			
Operating Expenses								
				548 721 322 S	107 522 919	5 120,479,725	\$ 46,905,956 \$	1,655,416
Operation and Maintenance Expenses			,		20,215,410	23,172,879	9,628,793	258,472
Depreciation and Amonization Expenses Description Credits and Arritetion Expenses				(8,656,053)	(1,540,948)	(2,135,228) 9,447 654	(755,034) 988 769	24,457
Property Taxes		NPT		8,211,450 6 761 006	1,560,240	1.506.949	623,647	17, 162
Other Taxes				(246.288)	(39,277)			(150)
Gain Disposition of Altowances		TXINCPF		26,916,596 \$	(1,673,726)	\$ (4,042,011)	\$ 2,599,323 \$	281,430
State and rederal income +axes consists Arcinement of Ourtaitable Service Rider Credit				(4,582,475)			- 440 AE? •	- 11 972
		SCP1	ŝ	4.582.475 \$	934.980	****R'1 //		
							- 110 CO11	(06.410)
Adjustments to Operating Expenses: Fliminate mismatch in fuel cost recovery		Energy		(31,644,777) \$	(5,046,623)	\$ (5,810,987) • (46 795)	\$ (2,110,684) \$	(908)
Remove ECR expenses		ECRREV		(248,468) \$	(777'64) (218'879'0')	(4541,167)	s (1.649,456)	(75,349)
Ejiminate brukered sales expenses		Energy De upp://		(24,123,142) 3 (2946,471) 5	(1.510.632)	\$ (1,090,913)	\$ (223,001) 1	(10,756)
Eliminate DSM Expenses		YREND		151,410 \$	(251,488)	\$ 1,068,029	\$ 491,740	•
r ear end adjustment Deserviction adjustment		DET		بری			2 227 840	6.140
Adjustment for change in depreciation rate				2,091,278 5	4/6/302 250 942	5 251,816	s 106,754	2.471
Labor adjustment		ā		• • • • • • • • • • • •				
Medical Expense (See Functional Assignment)		LBT		ر ي ا	•		* · · · · · · · · · · · · · · · · · · ·	- (554)
Adjustment for pension/post real delication (data a unoronal Adagament) Storm domore adjustment		SDALL		(473,014) \$	(168,017)	(153,325)	י (כייס אס) אס איז	
Sturnt damage adjustments Fliminate advertising expenses (See Functional Assignment)		REVUC			- 10 EE A	5 · · · · · · · · · · · · · · · · · · ·	5.351	218
Adjustment for amortization of ESM audit expense		R01		58,333 \$	69.064	\$ 77,387	\$ 30,129	1,063
Amortization of rate case expenses		LBT		,				
Remove Amonization of one-unity costs (peer a recent providence) Advisorment for initiations and damages account 925 (See Functional Assignment)	iment)	OMT				\$ 747 408	3 208.413	7.138
Adjustment for VDT net savings to shareholders		181		2,895,000 \$	724,972	4 766 762	2.020,807	46,767
Adjustment for merger savings		181		10,900,023 \$	(682.778)	\$ (685,157)	\$ (290,463)	6,722
Adjustment for merger amortization expenses		PLTRT		843,344 \$	150,132	\$ 208,032	5 77 932	3,302
Adjustment for affect of accounting change		DET		8,434,618 \$	1,929,348	\$ 2,211,60/	5 810,907	1.482
Adjustment for IT staff reduction		LBT		(601,682) \$	(150,674)	(121,158) c (771,350)	(288,961)	(12,243)
Adjustment to remove Atstorn expenses		РLРРТ . вт		(3,126,995) 5	(100'0CC)	(mm ⁻¹ · · ·)		
Adjustment for corporate lease expense				120.391	21,803	\$ 23,030	\$ 11,043	451
Adjustment for sales tax retund		PLPT		1,959,879 \$	348,897	5 483,452	5 181,110 • /774,008/	(6 178)
Adjustment for the storm		SDALL		(5,277,336) \$	(1,874,535)	• (1,710,017) • 36,005	14.018	495
Adjustment for management audit fee		OMT		163,982 \$	32,133 /116 759)	(144.138)	\$ (53,008)	5 (2,350)
Adjustment for Retirement of Green River Units 1 & 2				<pre>\$ (000'00')</pre>	(10,101) (54,947)	\$ (88.836)	\$ (42,731)	\$ (1,66'
VDT Amortization and Surcredit		VUIREV		(35,904,718)	(5,665,788)	(4,781,363)	(1,194,417)	(114,142
l otal Expense Anjustments	901 1		4	633.180.928 \$	122,919,145	\$ 137,075,229	\$ 59,085,206	\$ 2,107,127
Total Operating Expenses	2		•	20 369 011 \$	1 672 788	5 (1.321,318)	\$ 6,039,145	\$ 499,025
Net Operating Income (Adjusted)			•			è	r 166 633 366	3 988 815
Net Cost Rate Base			•7	1,412,033,543 \$	328,74	n'i i c 🗧	•	ĺ
			ļ	10.0	J 5 1 9	1.36%	3.88 %	10.2

Exhibit _____ (SJB-3) Page 5 of 8

> Avg Excess Prod Trans Allocation All other KUUC Corrections Included

12 Months Ended September 30, 2003

	-	Allocation	amo-	combined Light & Co Power I bs	Power I PP	Power	TOD Primary LCIP	TOD Transmission LCIT		Secondary HLFS	Primary HLFP
Description	Name	Vector		0	1		ľ				
Operating Expenses											
				114 460.537 \$	26,120,793	391,342	\$ 52,102,212	\$ 14,624,123	123 \$	9,449,840 \$	17,751,732
Operation and Maintenance Expenses Demonistion and Amortization Exnenses			•	14,434,387	3,157,715	45,493			184	120,820,1	(254,680)
Regulatory Credits and Accretion Expenses				(1,740,378)	(422.796)	(6.730)	(780,390) 748 746		463	97,063	177,219
Property Taxes		NPT		1,334,945 540 535	230,000	3.032			160	68,109	124,355
Other Taxes				550,023	(14.367)	217	(29,956)		(207)	~	(10,413)
Gain Disposition of Allowances		TXINCDE		13 932 976 S	3.168,662	\$ 93,531	\$ 4,904,205	69	478 \$	1,028,417 \$	1,890,385
State and Federal Income Taxes			•		(181,381)	. •	(271,654)	÷	037)		
Specific Assignment of Curtallable Service Rider Credit		er Di		1 047 059 \$	240.238	\$ 4,049	\$ 441,260	"	101,228 \$	78,321 \$	145,724
Allocation of Curtailable Service Rider Credits		201	•								
ádiustmente to Obacating Exnepses.							•	(012 at 1 4 7 10)	7101 6	\$ 1200 2027	(1 337 916)
Eliminate mismatch in fuel cost recovery		Energy	•••	(7,511,155) \$	(1,845,959)	(27,8/9) • (103)	5 (3,646,931) 6 (23,825)	- -	(6.834) \$	(4,435) 5	(8,322)
Remove ECR expenses		ECRREV		(56,898) \$	(12,009)	(190) (190) (190)			(874,249) \$	(552,511) \$	(1,045,554)
Eliminate brokered sales expenses		Contract,	•	(010'00'0') *	(12,138)	(473)		•**			
Eliminate DSM Expenses		YREND	• • •	(360,354) \$	71,010	164 ,672	•	م	•••		(324,055)
Tearsoisting adjustment		DET	-		ŀ			<i>w</i> •	•••	24 364 5	44.391
Adjustment for change in depreciation rate		DET	•	341,564 5	74,722	1,0// 2 1,0//	5 13/,4/4 e 60,482	A 14	J5.597 5	11.191 \$	20,309
Labor adjustment		LBT	•	174,630 \$	7BU,25	,		•			
Medical Expense (See Functional Assignment)		IRT			•	•	\$	ŧð	. ,	••• • •	1000 17
Adjustment for pension/post retir penem (see nunctional Assignment)		SDALL		(42,357) \$	(5,656)		\$ (9,718)	م	•	(2,245) 5	(enn'c)
Siom damage aqusment Etiminate advertising expanses (See Functional Assignment)		REVUC	47	• ••	•			•••	, e	1 047	1 969
Adjustment for amortization of ESM audit expense		R01	•	13,383 5	3,000	42	5 5,508 • 33,455		- 200 -	9 020 S	11,402
Amontization of rate case expenses		OMT	\$	73,521 \$	16,778	107		• •	• • •		. •
Remove Amortization of one-utility costs (See Functional Assignment)		LBT	•••		•	. , ~ ~		• •A	- 67 -		,
Adjustment for injunes and damages account 925 (See Functional Assignment)	(ment)	WO -	••	FOA FOF	92 699	1291	174,732	- 47	45,061 \$	32,332 \$	58,672
Adjustment for VDT net savings to shareholders			n u	3 305,659	607.386	s 8.457	•••	-	251 \$	211,847	384,434
Adjustment for merger savings			• •	(475,143) \$	(87.303)	s (1.216)	**	6	438) \$	(30,450) 5	(55,25)
Adjustment for merger amoruzation expenses Adjustment for MiCO schedule 10 expenses		PLTRT	- 10	169,562 \$	41,192	\$ 656		6 7 6	21,177 5	14,133 8	179.035
Adjustment for effect of accounting change		DET	ŝ	1,377,610 \$	301,371	5 4,342	104,400	A 4	23,073 \$	(6,720) 5	(12,194)
Adjustment for IT staff reduction		LBT	•••	(104,854) 5	(19,200)	(200) (200)		- u	(78.520) \$	(48,694) \$	(92,003)
Adjustment to remove Alstom expenses		PLPPT		c (117,82d)	(ee) (70+)			• •/3	•	• 7	•
Adjustment for corporate lease expense		5	• •	7 620 5	6.192	84 84	S 11,575	••	3,278 \$	2,161 \$	4,064
Adjustment for sales tax retund			,	394.051 \$	95,728	\$ 1,524	••	\$	49.213 \$	30,519 5	104°,70
Adjustment for UMU Nox experise Adjustment for ine storm		SDALL		(472,573) \$	(63,098)	•	\$ (108,425)				5 305
Adjustment for movement and the		OMT	••	34,206 \$	7,806	\$ 117	~			2 47077 0 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1	(76.8.16)
Adjustment for Retirement of Green River Units 1 & 2		OMPPT	•	(158.899) \$	(38,919)	\$ (597)	• •	<i>.</i>	(12,541)	(8 27 1) \$	(15,45
VDT Amortization and Surcredit		VDTREV	•	(106,432) 5 /0.460.436)	(23,944) (23,54,437)	5 (J00) 127.766	(5)		(1,546,926)	(965,804)	(2, 162,086)
Total Expense Adjustments				(001'001'a)							10 540 47
Total Operating Expenses	TOE		••	134,961,804 \$	30,221,647	\$ 662,586	\$ 57,888,992	2 \$ 15,851,611	1 611 5	10,645,271 5	C/1 '07C'A
kist Assessment (Adirochad)			\$	24,576,405 \$	5,566,350	\$ 154,067	\$ 8,615,032	÷	2,945,773 \$	1,807,345 \$	3,319,438
					000 010 01	• 50A 716	4 90 292 938		22.427.620 \$	16,112,733 \$	29,237,650
Net Cost Rate Base			•	225,972,090	40,940,039	,				/100 11	14 164
				40.020/	14 T 7 4	7886 66	2.76%		13 13 %	72	07.11

Avg Excess Prod Trans Allocation All other KTUC Corrections Included

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12 Months Ended September 30, 2003

	Def Name	Allocation Vector	Coal N	Coal Mining Power Primary MPP	Coal Mining Power Transmission MPT	Large Power Mine Power TOD Primary LMPP		Large rower mine Power TOD Transmission LMPT	Combin P C	Combination Off- Peak CWH
										000 000 1
Operation and Maintenance Expenses			ş	3,484,867	5 2,866,264	•	550.6/8 \$	3,501,955	•	786 346
Depreciation and Amortization Expenses				458,/b9	C12'C2C		(27,826)	(63.458)		(8.920)
Regulatory Credits and Accretion Expenses		101		(011,10) 43,702	10,232		10.699	40.508		25.819
Property Taxes				2027CH	21.677		13,823	28,425		18,117
Other Laxes				(1839)	(1.608)	_	(810)	(1,897)		(193)
Gain Uisposition of Allowances		TXINCPF	\$	499.613	366,025	~	119,969 \$	351,568	••	(461,502)
State and regeral incurre raxes Snactic Accimment of Curtaitable Service Rider Credit			•	•			•	•		•
Allocation of Curtailable Service Rider Credits		SCP1	*	26,400	\$ 23,067	\$	10,168 \$	29,038	•	4,940
Adjustments to Operating Expenses. Fliminate mismatch in final cost recovery		Enerov	÷	(236,347)	\$ (206,595)	•	(104,115) \$	(243,795)	••	(24,816)
		ECREV		(1,810)	5 (1,443)		(696)	(1.713)	~	(156)
Eliminate brokered sales expenses		Energy	-	(184,700)	\$ (161,450)	5	(81,363) 5	(190,521)	n .	(585,81)
Eliminate DSM Expenses		DSMREV	•••			•	•	- VA 266)	• •	(13.589)
Year end adjustment		YREND		(141,450)	\$ (100,932)	••	• •		, .,	-
Depreciation adjustment			~ ~	10.856	2 PGF		4.940 \$	10.089		6,776
Adjustment for change in depreciation rate		I BT	•••	4.407	3,239		1,967 \$	4,050	•	4,311
Lador adjusiment Medical Evenes (See Functional Assimment)		j	•							
Advisioned Expense (See Functional Assignment) Advisional Assignment)	ient)	LBT	••			5	• •	,	. ,	
Storm damage adjustment		SDALL	••	(860)		•••	(362)		•••	(acc'r)
Eliminate advertising expenses (See Functional Assignment)		REVUC				5			••	- 27
Adjustment for amortization of ESM audit expense		R01	-	430			000	2 2 4 9	• •	Ě
Amortization of rate case expenses	4	TMO		2,235	*	÷.				
Remove Amortization of one-utility costs (See Functional Assignment)	nent) I Arriananati		~ ~	, ,	•••		,	•	-	,
Adjustment for Injunes and darages account 323 (Gee numerical Assignment) Adjustment for VDT not equipme to absorb idans	huannikeer n	LBT		12.731	5 B,359		5,683 \$	11,701	ŝ	12,454
Adjustment for worses serings to anarchice a			- 14	83.418	5 61,320		37,237	76,667	••	81,602
Adjustment for memer amortization excenses		LBT	\$	(11,990)	\$ (8,814)		(5,352)	(11,020)	\$	(11,729)
Adjustment for MISO schedule 10 expenses		PLTRT	••	5,954	\$ 4,70	•••	2,711	6,183	<i>.</i> , .	999
Adjustment for effect of accounting change		DET	••	43,785	\$ 31,038	•••	19,923	4U,533	~ •	170 17
Adjustment for IT staff reduction		LBT		(2,646)	(1,945) (1,945)		(131,151)	(704'7)	•••	(000°7)
Adjustment to remove Alstom expenses		PLPPT		(22,076)	5 (11,43	<i>.</i>	* (750'01)	(47£'77)		
Adjustment for corporate lease expense			<i>.</i> .	, uuu		<u>م</u> .	, E E	947		12
Adjustment for sales tax refund		R01	<i>.</i>	888			7 000 4	110 168	• •	7 020
Adjustment for OMU Nox expense		PLPPT	<i>.</i>	13,835		••	1114 11		•••	(39.675
Adjustment for ice storm		SDALL	<u>م</u> .	(0,040)			463	1 047		359
Adjustment for management audit fee			~ ~	(5 171)	 (4.381) 		(2.302)	(5,345)		(610)
Adjustment for Retirement of Green Kiver Units 1 & 2			••	181	 (1,00,1) (2,696) 		(1.291)	(3,165)	-	(28)
VUT Amontization and surgreat Total Expense Adjustments			•	(440,445)	(438,658)		(130,429)	(736,858)		16,985
Total Onerating Expenses	TOE		**	4,039,922	3,166,621	-	1,764,022	3,575,639	*	1,084,553
			•1	869.192	5 668,815		229,986	634,600	••	(652,432)
Net Cost Rate Base			.,	7,085,179	\$ 4,970,085	••	3,220,039 \$	6,486,097		4,697,715
			ŀ	10 2 6 4	12 AB4		7 114	2.78%	Ļ	13.59%

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> Avg Excess Prod Trans Allocation All other KIUC Corrections Included

KENTUCKV UTILITIES Cust of Service Study Class Allocation 12 Months Ended September 30, 2003

Operating Expenses Operation and Maintenance Expenses Operation and Amortzation Expenses Regulatory Credits and Accretion Expenses Property 1 axes Colin Disposition of Movances Calm Disposition of Movances		Vector		AES	55	Σ	St Lf					
Determine Expension Operation and Amortration Expenses Regulatory Credits and Amortration Expenses Property 1 zaxes Conf. Divertiances Cain Dipersion of Allowances												
Deration and Maintenance Expenses Depreciation and Amorization Expenses augulory Creatis and Accretion Expenses Topery Taxes Sub Disposition of Allowances 			•		202 203	553 535	3 532 608	330.30	•	3,082,355 \$	486,496 \$	12,663,868
Depreciation and Amortization Expenses Regulatory Credits and Accretion Expenses Diperty Taxes Sain Dipestion of Allowances			^	0,5/2,049 4	110 060	114.189	1.879.564	216,405		960,855	153,599 \$	1,541,360
Agguistory Credits and Accretion Expenses Property Taxes Gain Diper Stray (Anowances Gain Dipersion of Anowances				/60 D80)	(11 850)	(8.266)		(1,274)	(†	(32,788)	(2,090) \$	(222,545)
/nperty 1axes Other Taxes Gain Disposition of Allowances		NPT		56,940	10,271	10,490	167,983	19,288		86.755	13,852 5	101 660
Other Taxes Gain Disposition of Allowances Fear		-		39,955	7,207	7,361	117		7	60,876	4 17/n	
Gain Disposition of Aliowances				(1.496)	(257)	(254)		(34)	()	(833)	(145) 5	(018'0)
		TXINCPF	*)	44,515 \$	(16,228)	\$ 26,438	\$ (418,832)	\$ 47,28	2	740,480 \$	00.1UI 4	(2,630,403)
Olate and require income rakes The support of numbers of the first of the Distor Annalis				,	•	1		•			•	(001'000'0)
Specific Assignment of Curraliable Service Miger Creati		1005		38.263 \$	6.563	\$ 6,225	, •	, 57	м	•		010,101
Aliocation of Curtailable Service Kider Credits		-	•									
								,	ł	9 (000 017)	140 6411 6	(128.821)
Adjustments to Operating Expenses. Principals Internation for final society and second		Energy	5	(192,211) \$	(32,967)	32,629)	**	s	• • •	(200's) 1		(6,20,000)
		ECREV	\$	(1,423) \$	(232)	\$ (262)	5 (1,953)		A .	e (no7'7)	(14 544) 5	(694 595)
remote tor expenses Eliminate horizant sales evonances		Energy	•	(150,209) \$	(25,763)	5 (25,499)		(7C+'C) C	• 17			-
Eliminate DSM Exponent		DSMREV	5	•	•	•			••	42 DBD 54	(11571) 5	,
Vest and adjustment		YREND	•	•	(11,965)	•	181,01 2	<u>,</u>	• •	• • • • •	5	•
Description adjustment		DET	*	•••	•			•••	, . ,	22 727 4	3 635 5	36.474
Adjustment for channe in debreciation rate		DET	~	14,402	2,605	2,702	1/4/44	171 G	÷.4	10 921 5	1.749 5	14,768
l abor adjustment		LBT	ş	5,396 \$	1,172	551,1 1,23		-	*		*	•
Medical Expense (See Functional Assignment)			,	•			•	v		•7		•
Adjustment for pension/post refir benefit (See Functional Assignment)		LBT				· · · · · · · · · · · · · · · · · · ·	(3854)		32) 5	(4,091) \$	(623) \$	(912)
Storm damage adjustment		SDALL		¢ (rac'7)	(700)	(1007)	•					•
Eliminate advertising expenses (See Functional Assignment)		REVUC	•••	• • •	58	67	3 462	- 47	68 \$	534 \$	282	1,412
Adjustment for amortization of ESM audit expense			~ ~	2 166 S	404	356	5 5	\$	212 \$	1,980 \$	312 \$	8,134
Amonization of rate case expenses		ET T	• •	• •/1	•		•	•	•	י פע י	, ,	•
Remove Amortization of one-utility costs (See Functional Assignment)	Menerali		• •	, va	,	•	ŝ	•••	••		,	- -
Adjustment for injunes and damages account azo (see Functional Assignment)	furger in the	IRT		15.589 \$	3,387	\$ 3,274	\$ 57,736	5 6.507	07 \$	31,551 5		503 024
Adjustment for VUL net savings to statisticularia		E I	•••	102,141 5	22, 193	\$ 21,450	••	~	\$	5 007 / 50 F	20,109 2	(AD 181)
Adjustment for merger savings		i El	- 49	(14,681) \$	(3, 190)	\$ (3,083)) \$ (6,128)	28) 5	(29,/14) \$	4 (BC) 4)	21.687
Adjustment for BASO schedule 10 expenses		PLTRT	5	6,731 \$	1,155	\$ 805	<i></i>	və 1		o, 194 &	14.659 5	147.107
Adjustment for affect of accounting change		OET	•	58,087 \$	10,505	\$ 10,895	•	••	***	(F 557)	(1 050) 5	(8.867
Adjustment for IT staff reduction		LBT	÷	(3,240) \$	(704)		(17'000) \$ (17'000)			(11844) 5	(1.839) \$	(80,394)
Adjustment to remove Alstom expenses		PLPPT	\$	(24,958) 5	(4,281)	(0016'7) S	.	•	• • •	-	••	
Adjustment for corporate lease expense		LBT	•	, o	- +	. 128 • 128	653 953		141 5	1,102 \$	162 \$	2,913
Adjustment for sales lax refund		RU1	•••	1 CT 0 2 T	2,683	1 872	ыл • • •		289 \$	7,424 \$	1,152 \$	50,388
Adjustment for OMU Nox expense			•	2 (DB 600)	(6.163)	(11.514)	5 5	3 (3,2	68) \$	(45,641) \$	(7,132) \$	(10,180
Adjustment for ice storm		SUALL	•••	1 008	188	5 165		~	\$ 56	921 \$	145 \$	3,783
Adjustment for management audit fee		OMOPT	• •	(4,726) \$	(811)	(109)) \$ (1,753)	~	(100) \$	(2,671) \$	(415) 5	(R#Z'BL)
Adjustment for Retrement of Green Kiver Units 1 & 2		VIDTREV		(2.682) \$	(445)	\$ (490	**		(557) \$	(4,383) \$	(020)	10/21
VDT Amortization and Surcfedit Total Evinence Adjustments			•	(203,096)	(42,604)	(36,039)) 435,715	65,053	53	101,124	(204)	008'001'11
	TOF		v	3 BR6 664 5	691.965	5 673,678	5,692,011	\$ 690,556	56 \$	4,998,723 \$	740,583 \$	11,219,199
Total Operating Expenses	1						e (564 633)	\ € 116 QBB	88. •	1.339.867 \$	159.803 \$	2,827,732
Net Operating Income (Adjusted)			•	198,807 \$	(656'()	* D4'/40	•	•				
Net Cost Rate Base			•	9,499,7D2 \$	1,728,194	\$ 1,B63,467	\$ 32,289,016	3,737,956	•	16,251,399 \$	2,583,135 \$	23,576,850
					0.001	742.4	2 - 0.81%		3.13%	8.24%	6.19%	11.99%

Avg Excess Prod Trans Allocation All other KTUC Corrections Included

Exhibit (SJB-3) Page 8 of 8

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

IN THE MATTER OF:

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

EXHIBIT (SJB-4)

12 Months Ended September 30, 2003

Daerijnijon	jo	ameli	Allocation Vector	Total Svetern	Residential Rate RS	All Electric Residentia: Rate FERS	General Service al Secondary GSS	Genera Pri	General Service Primary GSP
Cost of Service Summary – Pro-Forma									
Operating Revenues									
Total Operating Revenue Actual				\$ 768,801,159	\$ 138,042,992	92 \$ 148,047,263	3 \$ 69,229,545	\$	2,810,354
Pro-Forma Adjustments:									
Eliminate unbited revenue			R01	675,000	\$ 122,243	53	*	-	2,528
Adjustment for Mismatch in fuel cost recovery			Energy	(35,887,728)	\$ (5,723,277)	•9	B) \$ (2,393,685)	5	(109,346)
Adjustment to Reflect Full Year of FAC Roll-in		FACRI	5	1,417,623	\$ 181,5	•	5 \$ 96,991	••	4,709
Remove ECR revenues		ECRREV		(25,039,979)	\$ (4,562,377)	•>	*		(91,531)
Adjustment to reflect Full Year of ECR Roll-in		ECRRI		17,986,813	\$ 3,208,1	.,	\$		66,930
Remove off-system ECR revenues			PLPPT	(776,418)	\$ (136,1		.,		(2,186)
Etiminate brokered sales			Energy	(22,575,669)	\$ (3,600,306)	06) \$ (4,145,611)	5 5		(68,786)
Eliminate ESM revenues collected		ESMREV	;	(4,604,742)	\$ (915.1	69	•••	\$ \$	(15,263)
Eliminate ESM FAC ECR from rate refund acct			Rot	1,630,147	\$ 295,2	.,	••	\$	6,105
Etiminate DSM Revenue		DSMREV		(2,942,935)	\$ (1,508,819)	••	4) \$ (222,733)	s ((10, 743)
Year end adjustment		YREND		251,167	5 (417,1	••	•	**	
Merger savings			R01	(2,564,269)	\$ (464,390)	•7		s ((8,603)
Adjustment for rate switching, increased interruptible credit		RATESW		(3,005,567)					
VDT Amortization and Surcredit			VDTREV	85,337	\$ 15,547	47 \$ 16,258	8 \$ 7,821	••	304
Total Pro-Forma Operating Revenue			(13,504,945) \$	\$ 693,449,939	\$ 124,538,048	48 \$ 136,041,798	8 \$ 64,868,705	~	2,583,471

Summer/Winter Average CP Prod Trans Allocation All other KTUC Corrections Included

KENTUCKY UTILITIES Cust of Service Study Class Allocation 12 Months Ented September 30, 2003

Description	Ref	Name	Allocation Vector	Combined Light & Power LPS	Combined Light & Power LPP	Combined Light & Power LPT	Large Commlind TOD Primary LCIP	Large Comm/Ind TOD Transmission LCIT	High Load Factor Secondary HLFS	High Load Factor Primary HLEP
Cost of Service Summary ~ Pro-Forma										
Operating Revenues										
Total Operating Revenue Actual				\$ 176,892,840	40 \$ 39,702,482	\$ 601,680	\$ 74,869,722	\$ 21,186,666	\$ 13,936,369	\$ 26,236,029
Pro-Forma Adiustments:										
Eliminate unbilled revenue			R01	\$ 154.859	\$	••	5 64,896	.,	•	•••
Adjustment for Mismatch in fuel cost recovery			Enerov	\$ (8,518,2	55) \$ (2,093,467)	5	е С	•••	•	312 \$
Adjustment to Reflect Full Year of FAC Rol-in		FACRI		\$ 365,7	~	ŝ	**	••	•	ŝ
Remove ECR revenues		ECRREV		\$ (5.734.0	•	\$	\$		•	•••
Adjustment to reflect Full Year of ECR Rolkin		ECRRI		\$ 4,133,9			-	••	•	••
Remove off-system ECR revenues			РСРРТ	\$ (163,316)	16) \$ (36,758)	559) (559)	**	\$ (17,276)	\$ (11,956)	: \$ (23,205)
Eliminate brokered sales			Energy	5 (5,358,5		\$	\$ (2,745,877)		*	\$
Eliminate ESM revenues collected		ESMREV	;	\$ (1,152,3	\$	•*	\$		•	**
Eliminate ESM.FAC.ECR from rate refund acct.			R01	\$ 373,9	••	**	••		•	••
Eliminate DSM Revenue		DSMREV		\$ (98,4		\$	•		•	, ,
Year and adjustment		YREND		\$ (597.7	•	\$	•			\$ (537,561)
Mercer savings			R01	\$ (588,297)	5		\$ (246,535)	S (69,809)	\$ (46,031)	(86,551)
Adjustment for rate switching, increased interruptible credit		RATESW			•		\$	(120,793)		
VDT Amortization and Surcredit			VDTREV	\$ 18,479	•••	\$ 65	\$ 8,140	•	\$ 1,514	\$ 2,828
Total Pro-Forma Operating Revenue			(13,504,945) \$) \$ 159,729,858	58 \$ 35,757,024	\$ 815,470	\$ 66,663,904	\$ 18,738,386	\$ 12,449,042	\$ 22,867,219

Summer/Winter Average CP Prod Trans Allocation All other KIUC Corrections Included

12 Months Ended September 30, 2003

Annaria di kana	Ref		Allocation Vector	Coal Mining Power Primary MPP	Coal Mining Power Transmission MPT	Large Power Mirre Power TOD Primary LMPP	Large Power Mine Power TOD Tran≉mission LMPT	Combination Off- Peak CWH
nesstiplinit	Į							
Cost of Service Summary – Pro-Forma								
Operating Revenues								
∓otal Operating Revenue Actual				\$ 5,638,015	\$ 4,546,102	\$ 2,199,244	\$ 5,422,766	\$ 503,555
Pro-Forma Adjustments:			100	4 976			-	
Eliminate unbilled revenue Advictor and for Microsofth in Arch cont recovery			Finerrow	s (268.036)	34,296)	\$ (118,074)	\$ (276,483)	\$ (28,144)
Adjustriserii 100 Alisatellari 11 Tuel austriseavely Adjinateeeetta Defact Erif Veer of EAC Oxfain		FACRI	(Events	12,843	. 47		••	•
		ECRREV		\$ (182.407		**	**	
Adjustment to refer to ill Vaor of FCR Politin		ECRRI		5 132,466		\$	•9	*
Demons off strated from 1500 monutes			PI PPT	\$ (4.780	*	*	*	\$
Remove bir-system ECK revenues Eliminate himfored sales			Enerav	\$ (168,612		••	••	
Climinate PSM revenues milected		ESMREV		\$ (33,089	*	•	•	<u>.</u>
Eliminate ESM.FAC.ECR from rate refund acct.		I	R01	\$ 12,018	•	••		
		DSMREV		•	••			
Veer and adjustment		YREND		\$ (234,645	•		•	\$ (22,542)
Nerder savinds			R01	\$ (18,905)	•	5 (7,311)	\$ (18,037)	\$ (1,639)
Adjustment for rate switching, increased interruptible credit VDT Amortization and Surcredit		RATESW	VDTREV	\$ 619	\$ 493	\$ 236	\$ 579	\$ 52
Tolai Pro-Forma Operating Revenue			(13,504,945) \$	s) \$ 4,890,463	3,832,000	\$ 1,977,473	\$ 4,199,870	\$ 429,005

Summer/Winter Average CP Prod Trans Allocation All other KIUC Corrections included

12 Moaths Ended September 30, 2003

						Flacteic Crace			Decorative Stree	Decorative Street Private Outdoor	r Gustomer		
Description	Ref	Name	Allocation	All Elce	All Elcetric School AES	Heating Rider 33	Water Pumping M	Street Lighting St Lf	Lighting Dec St Lt	Lighting PO Lt	8		Special Contracts
Cost af Service Summary — Pro-Forma													
Operating Revenues													
Totał Operating Revenue – Actuał				•	4,474,128 \$	771,749	\$ 821,029	\$ 5,630,511	\$ 816,571	\$ 6,574,367	7 \$ 967,888	•••	IB,879,292
Pro-Forma Adjustments:													
Eliminate unbilled revenue			RO1	•	3,911 \$	675	••	5	••	••	\$	•	16,335
Adjustment for Mismatch in fuet cost recovery			Energy	\$	(217,983) \$	(37,387)		••		-	••	•	(1,007,994)
Adjustment to Reflect Full Year of FAC Roll-in		FACRI	3	•	9,719 \$	881	\$ 1,457	\$ (1,021)	\$ (74)	i \$ (3,573)	3) \$ (2,582)		45,827
Remove ECR revenues		ECRREV		•	(143,373) \$	(23,364)	•	\$	•••	•7	•	*	(691,956)
Adjustment to reflect Full Year of ECR Roll-in		ECRRI		\$	104,270 \$	17,741	•	••	5	~	••	•••	493,730
Remove off-system ECR revenues			PLPPT	•	(5,289) \$	(206)	••	*	•7	5	••	*	(23,684)
Eliminate brokered sales			Enerov	•	(137,125) \$	(23,519)	••	\$	57	••	•	*	(634,093)
Eliminate ESM revenues collected		ESMREV	5	\$	(21,999) \$	1 124	•	*	<i>6</i> 3	•*	•	s	(133,593)
Eliminate ESM.FAC.ECR from rate refund acct.			R01	•	9,445 \$	1,630	••	•7	•••	\$	•	**	39,449
Eliminate DSM Revenue		DSMREV		••	••	1	•	\$	**	\$		\$	•
Year end adjustment		YREND		*	•	(19,849)		\$ 16,889	\$ 12,240	\$ 71.430	0 5 (19,194)	*	•
Merger savings			R01	5	(14,857) \$	(2,564)	\$ (2,722)	\$ (20,307)	\$ (3,001)	~		\$	(62,054)
Adjustment for rate switching, increased interruptible credit		RATESW										~	2,777,732)
VDT Amortization and Surcredit			VDTREV	\$	491 \$	81	\$ 90	\$ 667	\$ 102	\$ 802	2 5 115	•7•	2,335
Total Pro-Forma Operating Revenue			(13.504.945) \$	\$ (0	4.061.337 \$	686,291	\$ 748,672	\$ 5,410,754	\$ 806,422	\$ 6,312,528	8 5 896,335	••	14,145,862

Summer/Winter Average CP Prod Trans Allocation All other KIUC Corrections Included KENTUCKY UTILITIES Cost of Service Study Class Allocation 12 Months Ended September 30, 2003

			Alfocation		Total	Residential Date DS	All Electric Residentia Dete FEDS	_	General Service Secondary GSS	General Service Primary GSP
XDENses			101004		-	2				
-										
Operation and Maintenance Expenses				•7	548,721,322 \$	106,362,519	\$ 119,256,735	735 \$	44,251,501 5	1,484,596
Depreciation and Amortization Expenses					88,376,624	20,064,000	23,951,791	187	8,910,473 1000 666)	747'06I
Regulatory Credits and Accretion Expenses			1011		(8,656,053)	(1,510,545) 1,545,545	008'007'7)		(000'760)	18 401
Property Laxes					6,211,45U	1,045,052	1 560 887	887	575 749	12 912
Comen Laxes Chain Discontring of Allowersons					1946, 1940	1770 051	145	(45 226)	(16.427)	(750)
State and Federal Income Taves			TXINCPE		26 916 596 5	1 152 038/	5 (3.910.688)	688) S	3.953.435 \$	382,134
Clair Acciment of Curtaitable Canica Dida: Cracit			Linear		(4 582 475)		•			
Allocation of Curtailable Service Rider Credits			scP	\$	4.582.475 \$	934,980	\$ 771	771.944 \$	449,462 \$	11.972
Adjustments to Onersting Expenses.										
rujuamente to Operanig Expenses. Eliminate mismatch in fuel cost recover			Fractor		131 644 777) \$	(5.046.623)	\$ (5 810.987)	\$ (285)	(2.110.684) \$	(96.419)
Demoise F/D eveneses					(1748 458) \$	(0,070,020)	(49	(46.795) \$	(22.742) \$	(806)
Filminate hmkered sales exnerses			Finerov		(24 729.742) 5	(3.943.832)	\$ (4,541,167)	167) \$	(1,649,456) \$	(75,349)
Eliminate DSM Expenses			DSMREV		(2.946,471) \$	(1,510,632)	\$ (1,090,913)	913) \$	(223,001) \$	(10,756)
Year and adjustment			YREND		151,410 \$	(251,488)	\$ 1,068,029	,029 \$	491,740 \$	•
Depreciation adjustment			DET			•	\$	•• 		
Adjustment for change in depreciation rate			DET		2,091,278 \$	474,779	\$ 567	567,487 \$	210,851 \$	4,632
Labor adjustment			LBT		1,002,076 \$	250,084	\$ 256	256,399 \$	102,685 \$	2,170
Medicat Expense (See Functional Assignment)	4				•			•	•	
Adjustment for pension/post retir benefit (See Functional Assignment)	nent)					-	~ •	(1E2 226) #	. 1 101751	, (55A)
Storm damage anjustment					(4/2/14)	(/ I A' 001)	9 w			(L.).
Eliminale adventsmg expenses (See Functional Assignment) Advictment for conscission of ECM audit connector					4 111 83	10 564		11 159	5 351 3	218
Aujustricht für attolitzation of Edward ducit expense Amortization of rate rate expenses			TWO		352 456 \$	68.319	92 92	76.601 5	28,424 \$	954
Remove Amortization of one-utility costs (See Functional Assignment)	mentì		LBT		• • 9	,	- 19	•••		•
Adjustment for injuries and damages account 925 (See Functional Assignment)	al Assign	ment)	TMO			•	. 03	••• •	•	•
Adjustment for VDT net savings to shareholders	0		LBT		2,895,000 \$	722,494	\$ 740	740,735 \$	296,657 \$	6,095
Adjustment for merger savings			LBT		18,968,825 \$	4,733,976	\$ 4,853,506	506 \$	1,943,777 \$	39,933
Adjustment for merger amortization expenses			LBT		(2,726,510) \$	(680,445)	(697	(697,625) \$	(279,391) \$	(5,740)
Adjustment for MISO schedule 10 expenses			PLTRT		843,344 \$	147,930	5 219	219,796 \$	67,485 \$	2/2/2
Adjustment for effect of accounting change			DET		8,434,618 \$	1,914,897	2,288	2,288,809 \$	820'411 \$	18,082
Adjustment for IT staff reduction					(601,682) \$	(150.159)	Sel) 5	(155,851)	 (aca'La) 	(107'1)
Adjustment to remove Alstom expenses			PLPPT		(3,126,995) 5	(2NG'84G)	410) + (014	* (7)A	feyz'nezì	(ano'o)
Adjustment for corporate lease expense						- 1 ana	, , , , , , , , , , , , , , , , , , ,	* UEU EC	11 043 5	451
Adjustment for CMUS Nex extenses					120,331	21, 200 343 780	• •	510 793 5	156.831	5519
Adjustment for ice storm			SDAIL		(F 277 336)	(1.874.536)	1 710.617	6171 \$	(774.008) \$	(6,178)
Adjustment for monocement and tas			UM1		163.082	31 786	35	35,639 \$	13.224 5	444
Adjustment for Retirement of Green River Units 1 & 2			OMPPT		(705.035) \$	(114.982)	s (141	(141.764) \$	(49,153) \$	(2,111)
VDT Amortization and Succedit			VDTREV		(466,280) \$	(84,947)	\$ (88	(88,836) \$	(42,731) \$	(1,661)
Total Expense Adjustments					(35,904,718)	(5,699,021)	(4,598,967	,967)	(1,353,943)	(128,337)
Total Operating Expenses		TOE		•	633,180,928 \$	122,093,908	\$ 136,984,925	925 \$	56,898,087 \$	1,952,294
Net Operating Income (Adjusted)				ŝ	60,269,011 \$	2,444,140	\$ (943	(943,126) \$	7,970,617 \$	631,177
				٠	1 417 DTT 542 6	376 FAA 574	4 387 931 477	\$ 225	145 003 625 \$	3 054 618
				,		L00'LL0'070			- 1	
Rate of Return				L	4.27%	0.75%		-0.25%	5.50%	20.66%

Summer/Winter Average CP Prod Trans Allocation All other KUUC Corrections Included

Exhibit (SJB-4) Page 5 of 8

12 Munths Ended September 30, 2003

		Allocation	3			Power	TOD Primary	TOD Transmission	Secondary	Primary UI CD
Description Ref	f Name	Vector		LPS	LPP	LPT				
Operating Expenses										
Contraction Contraction			•	117 230.078 \$	26.376.329	369,251	\$ 53,278,685	\$ 14.752,145	9,739,162	\$ 18,395,937
Operation and Amortization Expenses			•	14,972,889	3,070,687	42,170	5,696,889	1,291,409	1,019,576	1,902,929
Regulatory Credits and Accretion Expenses				(1,820,763)	(409,805)	(6,234)	(169, 768)	(192,609)	(133,293)	(AD/ 907)
Property Taxes		NPT		1,405,766	289,796	4,005	536,034	0L/7Z1	90,100 67 439	126,155
Other Taxes				986,430	203,351	2,810	040'110 (340 060)	00,100	(5.503)	(10.413)
Gain Disposition of Allowances				(HCH'RC)	(14.357)	(117)		4 1 7 7 6 7 7 6 1	G18 408	1 625 425
State and Federal Income Taxes		TXINCPF	n	12,611,315 \$	3,1U3,/5U1,5	50/'CA	(271654)	(499.037)		,
Specific Assignment of Curtailable Service Rider Credit					(100,101)		441.050	101 228	78.321	\$ 145.724
Allocation of Curtailable Service Rider Credits		scP	•	\$ 650,760,1	240,236	R+0.4	nn7'i 11	* nyy'ini		
Adiustryante to Onarating Evanaces.										
Aujuanizana wa Operating Expension. Filiminata mismatch in fuel cost recovery		Energy	•	(7,511,155) \$	(1,845,959) 3	(27,879)	5 (3,848,951)	\$ (1,118,710)	(200'202)	5 (1,337,916) 6 (1,337,916)
Remove ECR expenses		ECRREV	\$	(56,698) \$	(12,809) \$	(193)	5 (23,825)	\$ (6,834)	(4,435)	(277) (0.327)
Eliminate brokerad sales expenses		Energy	*	(5,869,813) \$	(1,442,579) 3	(21,787)	5 (3,007,876)	5 (874,249)	(116,266) .	
Eliminate DSM Expenses		DSMREV	\$	(88,559) \$	(12,138)	(4/3)				5 (324.056)
Year end adjustment		YREND	6	(360,354) 5	010,17	719491				
Depreciation adjustment			•	3E4 307 6	77 667	800	134 807	30.559	24,126	\$ 45,029
Adjustment for change in depreciation rate			<u>ه</u> و	177 680	31.594	428	59,843	\$ 14,658	11,134	\$ 20,462
Labor adjustmeni Modiani Evenano 7000 Eurotional Assimmanti		3	,							
Medical Expense (See Function Assignment) Adjuctment for papelophoet ratic henefit (See Functional Assignment)		LBT	5	· ·	,	•		•		
Storm damage adjustment		SDALL	. 19	(42,357) \$	(5,656) 3	,	\$ (9,718)	•	5 (2,245)	\$ (3,009)
Fliminate advertising expenses (See Functional Assignment)		REVUC	÷	· ·		•	, , , , , , , , , , , , , , , , , , ,			, , , , , , , , , , , , , , , , , , ,
Adjustment for amortization of ESM audit expense		ROI	••	13,383 5	3,000	45	5,608	5 1.588 - 1.588	5 1,04/ 6 766	5 1,809 6 11,816
Amortization of rate case expenses		OMT	ŝ	75,300 \$	16,942	250	34,222	9/4/9	007'0	, , , , , , , , , , , , , , , , , , ,
Remove Amortization of one-utility costs (See Functional Assignment)	()	LBT	\$			•		•		
Adjustment for injuries and damages account 925 (See Functional Assignment)	ssignment)	OMT	69		1 1 0 1 0	966 1	173 887	40 14A	32 168	s 59.114
Adjustment for VDT net savings to shareholders				010,010 0 010,010 0 000 0	5 477 I B	101 B	1 132,806	5 277.474	210.770	\$ 387,328
Adjustment for merger savings		191	• •	(ALT 1000,0	(85.962)	(1.164)	5 (162,825)	\$ (39,883)	5 (30,295)	\$ (55,673
Adjustment for merger amoratation expenses		PLTRT		177.394 \$	39.927	607	5 74 997	\$ 18,766	\$ 12,987	\$ 25,206
Adjustment for affact of accounting change		DET		1,429,005 \$	293,065	4,025	543,708	\$ 123,251	3 08 308	\$ 181,614
Adjustment for 1T staff reduction		LBT	*	(106,636) \$	(18.970)	t (257)	\$ (35,932)	\$ (8,801)	(6,636)	5 (12,286
Adjustment to remove Alstom expenses		PLPPT	•	(657,750) \$	(148,042)	(2,252)	\$ (278,078)	\$ (69,580)	(48, 152)	5 (93,450
Adjustment for corporate lease expense		LBT	••	• •		, ?			2	4 064
Adjustment for sales tax refund		R01	*	2/,620 \$	261.9		1,000	41.610	30,180	58.576
Adjustment for OMU Nox expense		PL PPT	•	4 12/214 • 16/2 0/17	97'/2/ /23 008/		4 (108 425)		\$ (25.051)	5 (33,566
Adjustment for ice storm		SUALL	. .	e (c/c/7/⊕) ≇ C//35	(acn'cn)	116	15.922	5 4,409	\$ 2,910	5,496
Adjustment for management audit fee		OMPDT	• •	(163.032) \$	30,172,121	(595)	\$ (80,530)	\$ (22,832)	\$ (14,643)	\$ (27,829)
Adjustment for regretinelli of discrimentation in a contraction and Converted		VDTRFV	• •	(106.432) \$	(23,944)	(363)	\$ (44,478)	\$ (12,752)	\$ (8,271)	\$ (15,454
Total Expense Adjustments				(9,350,353)	(2,374,142)	127,021	(5,239,976)	(1,584,226)	(968,248)	(2,156,448
Total Operating Expenses	TOE		ŝ	137,073,963 \$	30,306,501	658,645	\$ 58,511,391	\$ 15,795,796	\$ 10,812,561	\$ 19,950,386
1 f One and the second s				22.655.896 \$	5,450,523	156,826	\$ B,152,513	2,942,590	\$ 1,636,481	\$ 2,916,834
			•							
Net Cost Rate Base			•	234,865,824 \$	47,671,184	646,017	\$ 88,640,445	\$ 18,897,574	5 15,965,493	5 29,033,550
				0.0 Pat	1447 24	1000 10	7:06 0	7012 81	10.25%	9.84%

Summer/Winter Average CP Prod Trans Allocation All other KJUC Corrections Included

Exhibit ____ (SJB-4) Page 6 of 8

12 Months Ended September 30, 2003

			Coal Mining Power	Coal Mining Power	Large Power Mine	Large Power Mine Power TOD Transmission		Combination Off- Beak
Description Ref Na	Allocation Name Vector	_	Primary MPP	MPT				CWH
Operating Expenses								
Operation and Maintenance Expenses		v>	3,395,813	5 2,890,098	5 1,458,586	6 \$ 3,459,123	*	1,173,678
Depreciation and Amortization Expenses			406,362	315,559	(20,891)		6	(7,613)
Regulatory Credits and Accretion Expenses	NDT		38.312	29.974	15,285		È.	24.987
Propeny taxes Other Tayes	-		26,883	21,033			зf	17.533
Gain Disposition of Allowances			(1,839)	(1,608)	(810)	0) (1,897) 5 5 380 997	2 2	(446 205)
State and Federal Income Taxes	TXINCPF	th	4)7/JCC	-	-	•	•	
Specific Assignment of Curtaliable Service Rider Credit Altocation of Curtaliable Service Rider Credits	SCP	••	26,400	\$ 23,067	5 10,168	8 \$ 29,038	* 8	4,940
Adjustments to Oneration Expenses:							•	(318 FC/
Eliminate mismatch in fuel cost recovery	Energy		(236,347) 74 810)	5 (206,595) c (1.443)	\$ (104,115) \$	19 VI	* *	(156) (156)
Remove ECR expenses	EURKEV	~ •	(184 700)	(161.450)	5 [8]	5 \$	21) \$	(19,393)
Eliminate brokered sales expenses	DSMREV		-			43	**	-
Clinishate Com Cypenses Year end adjustment	YREND	\$	(141,450)	\$ (165,932)	,	\$ (424,256)	5	(13,589)
Depreciation adjustment		••••		5 7 AE7	384	0 S 9.400	, ,	6,569
Adjustment for change in deprecision rate	UEI		4,110 4,110	3,185	1,704	• •/>	\$	4,261
Labor adjustment Medical Economy (See Functional Assimment)	3	•		•				
Adjustment for pension/post retir benefit (See Functional Assignment)	LBT	\$			5 · ·	99 40 10 10	-	, (3.556)
Storm damage adjustment	SDALL	•	(96U)		<u> </u>		•••	
Eliminate advertising expenses (See Functional Assignment)	REVUC	~ <u>~</u>	-	344	\$ \$		410 \$	37
Adjustment for amortization of ESM audit expense	DMT	• •	2,181	\$ 1,856		937 \$ 2,222	22 \$	754
Amonization of rate case expenses Remove Amonization of one-utility costs (See Functional Assignment)		•	. '		•		•	ı
Adjustment for injuries and damages account 925 (See Functional Assignment)		.				- 11 224	• •	12 311
Adjustment for VDT net savings to shareholders		• •	11,873	5 9,201 ¢ 60.384	••	9 1 4	• •	80,664
Adjustment for merger savings			(11,187)	\$ 00,204 \$ (8,665)	• •	36) \$ (10,571)	5 (F	(11,594)
Adjustment for merger amortization expenses		• •	5.192	5 4,561		•••	59 \$	742
Adjustment for whole schedule to expenses Adjustment for affect of accountion change	DET		38,783	\$ 30,117	•	ŝ	5 2	26,493
Adjustment for IT staff reduction	LBT	•	(2,468)	(1,912)	(1,023)	23) \$ (2.333)	• • •	(12,555)
E.	PLPPT	<u>ه</u>	(19,250)	5 (16,910) •	~ ~		~	/m/
Adjustment for corporate lease expense		•	RR	, 205 207		343 5 8	847 \$	77
Adjustment for sales tax refund			12.065	5 10,599		30 \$ 13,383	83 \$	1.724
Adjustment for LMU Nox expense	SDALL	• • •	(9,598)		s.	\$9	•••	(39,675)
Adjustment for management audit fee	OMT	~	1,015	5 864	5		84 8	35T (EEB)
Adjustment for Retirement of Green River Units 1 & 2	OMPPT	•••	(5,056)	5 (4.424) 5 (4.424)	(7,18U)	~ •	ور) م	(286)
VDT Amortization and Surcredit Total Expense Adjustments	VDTREV	~	(3,361) (452,152)	\$ (2,030) (440,842)	5	98) (743,380)	6	16,039
	TOE	\$	3,943,765	\$ 3,173,297	5 1,670,809	09 \$ 3,526,232	32 \$	1,059,758
Net Onerstinn Income (Adjusted)		\$	946,698	\$ 658,703	\$ 306,664	64 \$ 673,639	39 \$	(630,752)
			6.316.969	\$ 4,828,552	\$ 2,539,011	11 \$ 6,059,060	\$ 090	4,569,377
		,				2.2. June 1		42.804
			7.0011	13 64%	42.08%			-13.60%

Exhibit _____(SJB-4) Page 7 of 8

> Summer/Winter Average CP Prod Trans Allocation All other KJUC Corrections Included

KENTUCKY UTILITIES Cust of Service Study Class Allocation 12 Months Ended September 30, 2003

Description

-47.213 47.213 (44.465) 25.7465) 25.7465) 25.7465) 25.7465) 26.7465) 26.7463 (9.8413) (9.613) 3.988 (10.1480) 3.988 (20.1680) (1.091,984) (1.091,984) 13,344,427 1,819,340 (264,040) 172,574 121,095 (6,918) 1,229,785 (3,530,403) 161,576 Special Contracts (888,821) (6,866) (694,595) 43,051 16,342 -. (912) 1,412 8,571 4,867 31,889 (4,584) (4,584) (3,574) (1,011) (1,225) (1,011) (1,225) (1,225) (1,011) (1,225) (1,225) (1,225) (1,225) (1,225) (1,225) (2,122) (463,102 142,222 (3,392) 12,781 8,968 (145) 97,215 (18,611) (330) (14,544) (11,571) 3,365 1,685 . (639) 78 297 Customer Outdoor Lighting . . 001 2,931,658 \$ 887,566 (21,847) 79,790 55,989 (333) 831,402 \$ (119,883) \$ (2,260) \$ (93,686) \$ 43,060 \$ - **5** (4,091) **5** 534 **5** 1,883 **5** 1,102 4,947 4,541) 876 (2,469) (4,383) 84,769 30,351 30,351 198,869 2,129 84,709 (6,308) (7,892) Decorative Street Private Outdoor Lighting Dec St Lt POLt 21,003 21,003 10,506 (4,417) (291) (3,452) -7,379 5,046 5,046 2,234 (3.02) (3.02) (3.02) (5.68) (4.455 (4.455 (4.455) (1.342) (1.342) (1.342) (1.342) (1.342) (3.368) (3.3 323,469 213,252 (804) 18,988 13,324 (34) 51,332 . . ** ** 3,413,013 1,824,395 (14,064) 162,741 114,196 (601) (347,969) 56,833 372,386 (53,525) 1,370 174,119 (11,812) (6,081) . (3,854) (77,281) (1,953) (60,394) 10,181 43,171 19,672 , 462 2,192 Water Pumping Street Lighting . . StLt \$ ** 616.278 143.003 (12,568) 13,228 9,282 9,282 (10,683) 3,745 3,745 3,527 3,527 1,224 13,648 13,648 (778) (778) , 128 2.846 (11,514) (794) (794) (794) (29,612) . (1,032) -6,225 (32,629) (262) (25,499) 3,384 1,296 . 396 589,892 \$ 98,439 (10,114) 9,166 6,432 6,432 (257) 4,093 \$ (32,967) \$ (232) \$ (25,763) \$ - 5 (11.965) \$. 6,563 2,329 1,107 . (552) 58 379 Electric Space Heating Rider 33 5 5 698 5 13,351 1 (28,599) 1 (28,599) 1 (28,599) 1 (28,599) 1 (282) 1 (218,172) (2,563) 338 2,020 2,020 14,479 94,479 94,479 94,479 5,745 (13,509) (21,302) (21,302) 3,145,245 540,813 540,813 50,496 50,495 35,433 (1,496) (1,496) . 38,263 (192,211) (1,423) (150,209) --5,012 All Elcetric School AES Allocation Vector Energy ECRREV Energy DSMREV MREV DET DET LBT TXINCPF LBT SEOALL SEOALL SEOALL R01 LBT LBT LBT LBT LBT LBT LBT R01 LBT CBT R01 CMT OMT VDTREV VDTREV ЦЧ SCP Depretent adjustment Deprection adjustment Lation adjustment for change in depreciation rate Lation adjustment for change in depreciation rate Lation adjustment for change in depreciation rate Medical Expense (See Functional Assignment) Storm damage adjustment Storm damage adjustment Eliminale advertising expenses Adjustment for amorization of ESM audit expense Amorization of rate case expenses Remove Amorization of ESM audit expense Amorization of rate case expenses Remove Amorization of ESM audit expenses Adjustment for morger surings to shareholders Adjustment for morger amoritization adjustment for morger amoritization adjustment for morger savings Adjustment for morger amoritization adjustment for morger amoritization adjustment for morger amoritization adjustment for morger amoritization adjustment for morger addine of expenses Adjustment for morger amoritization adjustment for morger amoritization adjustment for morger addine appense Adjustment for morger addine addine Adjustment for morger add Name Ϋ́ε Property Taxes Other Taxes Gain Disposition of Allowances State and Federal Income Taxes Specific Assignment of Curtaliable Service Rider Credit Allocation of Curtaliable Service Rider Credit Adjustments to Operating Expenses: Eliminate mismatch in fuel cost recovery Remove ECR expenses Eliminate brokered sales expenses Eliminate DSM Expenses Year end adjustment Operation and Maintenance Expenses Depreciation and Amortization Expenses Regulatory Credits and Accretion Expenses **Operating Expenses**

Summer/Winter Average CP Prod Trans Allocation All other KJUC Corrections Included

Exhibit (SJB-4) Page 8 of 8

8.28%

7.41%

9.65% 15,177,086

3.32%

0.52%

60%

75%

4.31%

2,416,359 \$ 179,090 \$

\$ 1,464,133 \$

----122,546 \$

3,691,737

31,480,324

2,285,839

1,557,703 \$

•••

••

(164,365) \$ •••

₩ ÷

13,773

11,855,443 2.290,420 27,651,808

717,246

4,848,395

683,875

5,575,119

734,899

659,024 \$ 27,266 \$

3,694,611 366,726 8,505,675

ğ

Net Operating Income (Adjusted)

Net Cost Rate Base Rate of Return

Total Expense Adjustments Total Operating Expenses

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

IN THE MATTER OF:

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

EXHIBIT (SJB-5)

KENTUCKY UTILITIES Cost of Service Study Class Allocation 12 Mouths Ended September 30, 2003

Description	Ref	ameN	Allocation Vector		Total Svetem	Residential Rate RS	All Electric Residential Rate FERS	General Service Secondary GSS	General Service Primary GSP
						-		i	
Cost of Service Summary – Pro-Forma									
Operating Revenues									
Total Operating Revenue – Actual				~	768,801,159 \$	138,655,960	146,073,598	\$ 69,616,315	\$ 2,805,997
Pro-Forma Adjustments: Etiminota unbilled revenue			801		675 000 .\$	122 245	\$ 125	\$ 61.916	\$ 2.528
Adjustment for Mismatch in fuel cost recovery			Energy		(35,887,728) \$	(5.723.277)	- 43	\$ (2,393,685)	\$ (109,346)
Adjustment to Reflect Full Year of FAC Roll-in		FACRI	6		1,417,623 5	181,54	.,	••	\$ 4,709
Remove ECR revenues		ECRREV			(25,039,979)	(4,562,377) \$ (4,715,925)	••	\$ (91,531)
Adjustment to reflect Full Year of ECR Roll-in		ECRRI			17,986,813 \$	3,208,16	₩	*	\$ 66,930
Remove off-system ECR revenues			рсррт		(776,418) \$	(158,416	.4	•7	\$ (2,028)
Eliminate brokered sales			Energy		(22,575,669)	(3,600,306	*	\$	\$ (68,786)
Eliminate ESM revenues collected		ESMREV	6		(4 604,742)	(915,119	17	**	\$ (15,263)
Eliminate ESM FAC ECR from rate refund acct.			R01		1,630,147 \$	295,220	4	5	\$ 6,105
Eliminate DSM Revenue		DSMREV			(2,942,935) \$	(1,508,819)		\$ (222,733)	\$ (10,743)
Year end adjustment		YREND			251,167 \$	(417,18	\$	••	•
Merger savings			R01		(2,564,269) \$	(464,390)	*7	5	\$ (9,603)
Adjustment for rate switching, increased interruptible credit		RATESW			(3,005,567)				
VDT Amortization and Surcredit			VDTREV		85.337 \$	15,547	\$ 16,258	5 7,B21	\$ 304

2,579,272

125,128,790 \$ 134,139,695 \$ 65,241,451 \$

(13,527,170) \$ 693,449,939 \$

Total Pro-Forma Operating Revenue

Summer CP Prod Trans Allocation All other KUUC Corrections Included

12 Months Ended September 30, 2003

Description	Ref	Name	Allocation Vector	Combined Light & Power LPS	Combined Light & Power LPP	Combined Light & Power LPT	Large Comm/Ind TOD Primary LCIP	Large Commlind TOD Transmission LCIT	High Load Factor Secondary HLFS	High Load Factor Primary HLFP
Cost of Service Summary – Pro-Forma										
Operating Revenues										
Ťotal Operating Revenue Actual				\$ 177,515,062	\$ 39,811,312	\$ 605,181	\$ 75,027,425	\$ 21,183,217	\$ 13,972,612	\$ 26,276,986
Pro-Forma Adjustments:										
Eliminate unbilled revenue			R01	\$ 154,859	\$ 34.715	\$ 526	5 64.896	\$ 18.376	\$ 12.117	\$ 22,783
Adjustment for Mismatch in fuel cost recovery			Energy	\$ (8,518,255)	5 (2,	\$ (31,617)	••	\$ (1,268,707)	\$ (801,803)	\$ (1,517,304)
Adjustment to Reflect Full Year of FAC Roll-in		FACRI	ł	\$ 365,749	••	\$	~	\$ 94,994	53,661	5 62,851
Remove ECR revenues		ECRREV		\$ (5,734,057)	÷	~		\$ (688,721)	\$ (446,972)	\$ (838,688)
Adjustment to reflect Full Year of ECR RolLin		ECRRI		\$ 4,133,949	••			\$ 492,058	316,548	\$ 606,165
Remove off-system ECR revenues			PLPPT	\$ (185,877)	\$	\$	\$ (74,764)	\$ (17,151)	\$ (13,270)	\$ (24,690)
Eliminate brokered sales			Energy	\$ (5,358,526)	\$		5	\$ (798,098)	5 (504,385)	\$ (954,481)
Eliminale ESM revenues collected		ESMREV	•	\$ (1,152,341)	\$ (264, 123)			\$ (137,016)	\$ (69,263)	\$ (160,668)
Eliminate ESM, FAC, ECR from rate refund acct.			RO1	373,990		5	.,	\$ 44.379	29,263	\$ 55.022
Etiminate DSM Revenue		DSMREV		\$ (98,441)	57	•	.,			
Year end adjustment		YREND		\$ (597,774)	•	•	•			\$ (537,561)
Merger savings			R01	\$ (588,297)	10	•	\$	\$ (69,809)	\$ (46,031)	\$ (86,551)
Adjustment for rate switching, increased interruptible credit		RATESW			•		\$ (64,186)	\$ (120,793)		
VDT Amortization and Surcredit			VDTREV	\$ 19,479	\$ 4,382	\$ 66	\$ 8,140	\$ 2,334	\$ 1,514	\$ 2,828
Total Pro-Forma Operating Revenue			(13,527,170)	\$ 160,329,520	\$ 35,861,908	\$ 818,844	\$ 66,815,888	\$ 18,735,062	\$ 12,483,970	\$ 22,906,692

12 Months Ended September 30, 2003

Description	Ref	Name	Allocation Vector	Coal Mining Power Primary MPP	Coal Mining Power Transmission MPT	Large Power Mine Power TOD Primary LMPP	Large Power Mine Power TOD Transmission LMPT	Combination Off- Peak CWH
Cost of Service Summers - Dec Former								
Operating Revenues								
Total Operating Revenue Actual				\$ 5,629,555	\$ 4,538,092	\$ 2,195,076	5,412,231	\$ 507,806
Pro-Forma Adjustments:								
Eliminate unbilled revenue			R01	\$ 4,976	5	\$ 1,924	\$ 4,748	5 432
Adjustment for Mismatch in fuel cost recovery			Energy	\$ (268,036)	\$ (234,296)	\$ (118,074)	\$ (276,483)	\$ (28,144)
Adjustment to Reflect Full Year of FAC Roll-in		FACRI		\$ 12,843	\$	\$ 2,865	\$ 11,438	1,179
A dimove ECK revenues		ECRREV		\$ (182,407)	\$ (145,445)	\$ (70,105)	\$ (172,666)	\$ (15,723)
Adjustment to reflect Full Year of ECR Roll-in		ECRRI		\$ 132,466	•7	\$ 51,614	\$ 127.076	\$ 11,770
Remove on-system ECR revenues			РГРРТ	\$ (4,473)	•	\$ (1.723)	\$ (4,920)	\$ (837)
Elimphate prokered sales			Energy	\$ (168,612)	~	\$ (74,276)	\$ (173,926)	\$ (17,704)
Tilminate EXM revenues collected		ESMREV		\$ (33,089)	5	\$ (11,418)	\$ (28,011)	s (2,590)
Eximinate ESM, FAC, EUK from rate retund acct.			R01	\$ 12,018	\$	\$ 4,648	\$ 11,466	\$ 1.042
		DSMREV		•		۰ ۲	•	
rear adjustment		YREND		\$ (234,645)	\$ (275,257)	•	\$ (703,778)	\$ (22,542)
Merger savings Adimetronal for only a single in a single of the single o			R01	\$ (18,905)	\$ (15,111)	\$ (7,311)	\$ (18.037)	\$ (1,639)
Voluments on take switching, increased interruptible credit VDT Amortization and Surcredit		RAIESW	VDTREV	\$ 619	\$ 493	\$ 236	\$ 579	\$ 52
Tatal Box Examination Brease								
			(13,527,170) \$	\$ 4,882,311	3,824,281	\$ 1,973,457	\$ 4,189,718	\$ 433,102

12 Muaths Ended September 30, 2003

			Allocation	All El	All Elcetric School	Electric Space Heating Rider	Water Pumping	Street (johting	Decorative Street Private Outdoor Linhting	Private Outdoor Linbting	Customer Outdoor Linhting	Canada Canada Canada Canada C
Uescription	Ref	Name	Vector		AES	33	×	StLt	Dec St Lt	POL	COL	Contracts
Cost of Service Summary – Pro-Forma												
Operating Revenues												
Total Operating Revenue – Actual				•7	4,507,053	777,396	\$ 819,029	\$ 5,595,719	\$ 814,583	\$ 6,520,320	\$ 959,498 \$	18,981,135
Pro-Forma Adjustments:												
Eliminate unbilled revenue			R01	¥7	3,911 \$	675	\$ 717	5.345	2 790	5 6.178	5 GD 5	16 115
Adjustment for Mismatch in fuel cost recovery Adjustment to Default rull VIIII and for the rule			Energy	÷	(217,983) \$	(37,387)	\$ (37,004)	\$ (87,643)	(2,009)	\$ (135,957)	\$ (21.106) \$	(1.007.994)
Aujustrient to Reneat Full Year of FAC KolHa Domaine CCD animatics		FACRI		*7	9,719 \$	581	\$ 1,457	(1,021)	\$ (74)	\$ (3,573)	\$ (2.582) \$	45.827
Adiinternation contraction for the form of the form		ECRREV		••	(143,373) \$	(23,364)	\$ (26,381)	\$ (196,772)	\$ (29,280)	(227.715)	\$ (33.264) \$	(691.956)
		ECRR		••	104,270 \$	17,741	\$ 19,017	\$ 144,134	\$ 21,362	156.721	24 687 S	493 730
Reinveron-system curricvenues Eliminate herbard antes			PLPPT	•••	(6.483) \$	(1,112)	\$ (1,055)			•		(27.376)
Climitate prokarad Sales			Energy	**	(137, 125) \$	(23,519)	\$ (23,278)	55, 133)	3 (3.151)	\$ (85.526)	5 (13.277) S	(634 093)
Eliminate EXM /evenues collected		ESMREV		Ð	(21,999) \$	1,124	\$ (4,856)	(37,564)	5 (5,964)	\$ (43,690)	5 (6.279) S	(133,593)
CIRCIMINATE COMPLEXUE TOTAL ALCENTION ACCI.			R01	•7	9,445 \$	1,630	\$ 1,730	12,909	5 1,508	\$ 14.921	5 2.192 5	39 449
		DSMREV		*7	• •	•	•		,			
		YREND		"	•• ,	(19,849)		\$ 16,889	5 12.240	5 71.430	\$ (19.194) \$	•
			R01	÷	(14,857) \$	(2,564)	\$ (2,722)	5 (20,307)	(3,001)	\$ (23,470)	5 (3.447) \$	(62 054)
		RATESW								•		(0 777 739)
VLI Amortization and Surcredit			VDTREV	•	491 \$	81	3 0	667	5 102	\$ 802	\$ 115 \$	2,335
Total Pro-Forma Operating Revenue			(13,527,170) \$	\$ (02	4,093,069 \$	691,733	\$ 746,744	5,377,223	\$ 804,505	5 6,260,441	\$ 888,250 \$	14,244,013

12 Moaths Ended Scptember 30, 2003

5 544.771.32 109.76.204 108.265.111 44.405.422 5 6 80.365.053 11.66.127 11.466.103 9.957.822 5 80.365.053 21.723.882 11.66.657 11.466.657 9.957.822 5 80.376.053 21.723.882 11.766.577 96.566 9.957.822 5 80.376.753 21.723.803 1.716.647 2.650.033 2.653.933 5 8.11.4505 1.050.105 3.44.903 7.71.944 449.462 5 2.45.272 8.43.473 5.64.903 2.553.933 5 449.463 5 2.45.272 3.44.903 7.71.944 449.463 5 5.53.933 5	Description	Ref Name	Allocation Vector		Total Svstem	Residential A Rate RS	All Electric Residential Rate FFRS	General Service Secondary Goo	General Service Primary Con
International Contraction International Contractinternatinternaternational Contraction Internatio	Operating Expenses								5
Pack/network Pack/network<	Operation and Maintenance Expenses			4					
Accordite Expenses NPT Control (Control) Control (Contro) Control (Contro) Control (Contro) Control (Contro) Control (Contro) Control (Contro) Control (Control) Control (Contro) Control (Control) Control (Control) Control (Control) Control) Control (Contro) Control) Control (Contro) Control) Control) Control) Control) Control) Control) <thcontro)< th=""> Control Con</thcontro)<>	Depreciation and Amortization Expenses			•	5 225'121'325 5		108,265,181		1,460,330
model NPT 371166 2005 2005 7776.55 <td>Regulatory Credits and Accretion Expenses</td> <td></td> <td></td> <td></td> <td>(8.656.053)</td> <td>(1 766 127)</td> <td>10,007,210</td> <td>229'/66'6</td> <td>183,943</td>	Regulatory Credits and Accretion Expenses				(8.656.053)	(1 766 127)	10,007,210	229'/66'6	183,943
Operating (a) (7) (2) (2) (2) (2) (2) (2) (2) (2) (2) (2	Property Taxes		NPT		8,211,450	2,003,584	1.716.557	920 028	(CLD/22)
Matrix mark Trancer C 48 280 T 13 13 T 45 230 T 45 30 T 14 44 T 44 47 T 44 45 T 45 30 T 14 44 T 44 45 T 45 30 T 27 300 T 27 300 <tht 27="" 300<="" th=""> T 27 300 <tht 27<="" td=""><td>Const Lakes Cain Dimoniform of Allowsees</td><td></td><td></td><td></td><td>5,761,996</td><td>1,405,920</td><td>1,204,512</td><td>645.586</td><td>12 125</td></tht></tht>	Const Lakes Cain Dimoniform of Allowsees				5,761,996	1,405,920	1,204,512	645.586	12 125
monten of constrained service from the Constrained Service from Constreaned Service from Constrained Service from Constrain	State and Endored Anona Tauco				(246,288)	(39,277)	(45,226)	(16.427)	(150)
Contraints for form of the control of the c			TXINCPF		26,916,596 \$	(3,211,541) \$	2.720,603	2,653,933	396,774
Operating Expense. Contrained Expense. <thcontrained expense.<="" th=""> Contrained Expense.</thcontrained>			915	÷	(4,582,475) 4 EP2 475 e				
Operating Element			5	•	¢ C/4/20014				11.972
Bergy and Construction and constru	Adjustments to Operating Expenses:								
CHREV CAREV Cade Status Constraints	cuminate mismatch in fuel cost recovery		Energy		(31,644,777) \$	(5,046,623) \$	(5.810.987)	C 110 684) S	(06.410)
Control Control <t< td=""><td>Remove ECR expenses</td><td></td><td>ECRREV</td><td></td><td>(248,468) \$</td><td>(45,272) \$</td><td>(46.795)</td><td>(22.742)</td><td>(806)</td></t<>	Remove ECR expenses		ECRREV		(248,468) \$	(45,272) \$	(46.795)	(22.742)	(806)
Amery Total (1) Total (1) <thtotal (1)<="" th=""> <thtotal (1)<="" th=""> <thtotal< td=""><td>Eliminate Drokered sales expenses Flimbate DSM Expenses</td><td></td><td>Energy</td><td></td><td>(24.729.742) \$</td><td>(3,943,832) \$</td><td>(4,541,167)</td><td>(1,649,456) \$</td><td>(75,349)</td></thtotal<></thtotal></thtotal>	Eliminate Drokered sales expenses Flimbate DSM Expenses		Energy		(24.729.742) \$	(3,943,832) \$	(4,541,167)	(1,649,456) \$	(75,349)
Meril for independent District 19,140 3 (23)430 3 10,60,00 3 41,140 3 Meril for medicination dependent and digrimming Territy is static set functional Assignment) ET 10,017 5,554,45 5,54,65 5,117 5,554,45 <td>Year end adjustment</td> <td></td> <td></td> <td></td> <td>(2,946,471) \$</td> <td>(1,510,632) \$</td> <td>(1,090,913)</td> <td>(223,001) 5</td> <td>(10,756)</td>	Year end adjustment				(2,946,471) \$	(1,510,632) \$	(1,090,913)	(223,001) 5	(10,756)
ment for infance control control <thcontrol< th=""> <thc></thc></thcontrol<>	Depreciation adjustment				\$ 014'101	(251,488) \$	1,068,029	491,740 \$	•
Adjustment) Lift 1,002,006 5 239,466 5 232,112 5 1,008,19 Control for persinal variationer) Left 1,002,006 5 239,466 5 236,112 5 1,008,19 Control for persinal variationer) Left 1,02,006 5 236,133 5 1,113 5	Adjustment for change in depreciation rate				2 001 278 6	511 AED •			
Mail Connectional Assignment) Express (See Functional Assignme	Labor adjustment		LBT		1 002 076 \$	* 0CN'+IC	10,144	235,634 5	4,353
Constraint Constraint <thconstraint< th=""> Constraint Constrai</thconstraint<>	Medical Expense (See Functional Assignment)					* not'so1	771 177		2,043
damage algement EDALL (473,014) (168,017) (153,325) (68,375) (68,375) (68,375) (68,375) (68,375) (68,375) (68,375) (68,375) (68,375) (68,375) (68,375) (68,375) (68,375) (68,375) (68,375) (68,375) (68,375) (68,375) (53,12)	Adjustment for pension/post retir benefit (See Functional Assign:	tent)	LBT		•		,		
at a dvertigation of Ease Functional Assignment) REVUC 5.333 5.131 5.3333 5.3333 5.333	Storm damage adjustment		SDALL		(473.014) \$	(168.017) \$	(153.325)	(EQ 375) €	, VEEN
ment for an intraction of EdM and expense R01 56333 10.564 11.158 5.351 5.265.001 5.561 5.361 5.265.001 5.531 5.265.001 5.531 5.265.001 5.531 5.265.001 5.531 5.265.001	Eliminate advertising expenses (See Functional Assignment)		REVUC			S			(becc)
OMT 32,4/5 5 70,5/1 5 53,4/1 2,3/5/1 5 23,6/1 5 <th< td=""><td>Adjustment for amortization of ESM audit expense</td><td></td><td>R01</td><td></td><td>58,333 \$</td><td>10.564 \$</td><td>11.159 5</td><td>5 351 5</td><td>218</td></th<>	Adjustment for amortization of ESM audit expense		R01		58,333 \$	10.564 \$	11.159 5	5 351 5	218
Merric for induction of menuing casts See Functional Assignment) LBT 2.855,000 5 749,660 5 553,266 313,796 5 Merric for VUT ret savings to hareholders LBT 2.855,000 5 749,660 5 553,256 313,796 5 Merric for VUT ret savings to hareholders LBT 12,966,551 5 7106,030 5 553,256 5 2055,530 5 5 53,256 5 313,796 5 2255,530 5	Amonization of rate case expenses		OMT		352,456 \$	70,512 \$	69,541 \$	29.807 \$	938
ment for indures and compares UNT 2 885, 10 7 49, 60 5 5 3 13, 76 5 ment for indures and compares LBT 2 865, 51 5 4, 911, 976 5 55, 256 5 3 13, 76 5 ment for meger savings LBT 18, 966, 825 4, 911, 976 5 4, 200, 314 2, 2065, 031 5 2, 205, 316 5 2, 205, 316 5 2, 205, 316 5 2, 205, 316 5 2, 205, 316 5 2, 205, 316 5 2, 205, 316 5 2, 205, 316 5 3, 31, 756 5 5, 205, 316 5 5, 205, 326 5 5, 205, 316 5 5, 205, 316 5 5 3, 31, 750 5 5 5 3, 31, 750 5 5, 205, 316 5 5 5 5 3, 31, 750 5 <td>Adjustment for initiation of one-utility costs (See Functional Assign</td> <td>rent)</td> <td>LBT</td> <td></td> <td>\$</td> <td>~</td> <td></td> <td></td> <td>ζ.</td>	Adjustment for initiation of one-utility costs (See Functional Assign	rent)	LBT		\$	~			ζ.
Rent for merger savings 131 2.855,000 5 749,660 5 6 31,736 5 31,736 5 31,736 5 31,736 5 31,736 5 31,736 5 31,736 5 31,736 5 31,736 5 31,736 5 326,531 5 326,531 5 2056,531 5 2056,531 5 32,734 5 7,205,374 5 2056,531 5 32,718 5 32,733 5 32,513 5 32,513 5 32,513 5 32,513 5 32,513 5 32,513 5 32,513 5 32,513 5 32,513	Adjustment for injuries and damages account 925 (See Function) Adjustment for VINT as review to characterized	l Assignment)	DMT		•	.		· ••	•
Terr Ion LBT 13.96.825 4.91.976 4.206.374 2.056.301 ment for merger amoritation expenses LBT 13.96.825 4.91.976 4.206.374 2.056.301 ment for merger amoritation expenses LBT 17.2071 (16.5.245) 2.056.301 ment for merger amoritation expenses LBT 84.3.344 (17.2071) (15.5.45) 2.056.301 ment for merger amoritation expenses LBT 84.3.346 (17.2071) (15.7.70) (15.5.245) 2.056.301 ment for remove Alstime expenses LBT (3.1.56.961) (15.5.701) (15.5.701) (26.5.703) (10.6.704) (26.5.703) (10.6.704) (20.5.703) (11.4.3 (25.2.035) (11.4.3 (13.5.771) (13.5.771) (13.5.771) (13.6.771) (13.6.701) (13.6.701) (12.2.203) (11.4.3.2.2.2.033) (11.4.3.2.2.2.033) (11.4.3.2.2.2.033) (11.4.3.2.2.2.033) (11.4.3.2.2.2.033) (11.4.3.2.2.2.033) (11.4.3.2.2.2.033) (11.4.3.2.2.2.033) (11.2.2.2.2.0.33) (11.4.3.2.2.2.0.33) (11.2.2.2.2.0.33) (11.4.3.2.2.2.2.2.2.2.2.2.2.2.2.3.3.3.3.3.3	Adjustment for merver servings to snarenoiders				2,895,000 \$	749,660 \$	653,266 \$	313,798 \$	5,901
Trent for MiSO schedule 10 expenses PLTR1 ULTR2 11 State 11 State 12 Clob 303 State 12 Clob 303 State 12 Clob 303 State 12 Clob 303 State 12 State 13 <	Adjustment for memera amortization expanses				18,968,825 \$	4,911,976 \$	4,280,374 \$	2,056,091 \$	38,668
ment for effect of accounting changes DET 643,344 5 173,201 5 173,206 5 92,318 5 92,318 5 92,318 5 92,318 5 92,318 5 92,318 5 92,318 5 95,711 5 65,218 5 96,3218 5 95,371 5 65,218 5 96,3218 7 96,3218 7 7 96,3218 7 7 96,3218 106,721 106,721 <	Adjustment for MISO schedule 10 evences				(2,726,510) \$	(706,030) \$	(615,245) \$	(285,535) \$	(5,558)
ment for IT staff reduction LBT (601, 502, 310 (1, 55, 301) (1, 55, 301) (1, 55, 301) (35, 301) (35, 301) (35, 301) (35, 301) (35, 301) (35, 301) (35, 301) (35, 301) (35, 301) (35, 301) (35, 301) (30, 704) (306, 704) <th< td=""><td>Adjustment for effect of accounting change</td><td></td><td></td><td></td><td>543,344 5 0 424 545 6</td><td>1/2,071 \$</td><td>142,065 \$</td><td>82,718 \$</td><td>2,203</td></th<>	Adjustment for effect of accounting change				543,344 5 0 424 545 6	1/2,071 \$	142,065 \$	82,718 \$	2,203
ment to remove Alstrum expenses PLPT (10,1024) (10,1024) (10,1024) (10,1024) (10,1024) (10,1024) (10,104)	Adjustment for IT staff reduction				010,954,0	2,0/3,316 5	1///8//26 \$	950,369 \$	17,555
Image:	Adjustment to remove Alstom expenses		PLPPT		(3 126 995) *	(100,001)	(133,71) 5 (616 760) •	(65,218) \$	(1,227)
Rev for sales tax refund R01 120,391 21,803 23,030 11,043 5 11,043 12,0466 12,010 12,010 </td <td>Adjustment for corporate lease expense</td> <td></td> <td>LBT</td> <td></td> <td>• (cooring) 'n/</td> <td></td> <td>< (no/'07c)</td> <td>(3Ub,/U4) 5</td> <td>(8,170)</td>	Adjustment for corporate lease expense		LBT		• (cooring) 'n/		< (no/'07c)	(3Ub,/U4) 5	(8,170)
Peril for care storms PLPT 1,956,879 5 330,155 5 192,200 5 nent for readim nent for readim (5,155,45) (1,17,151,45) (1,27,040) 5 (1,27,040) 5 (1,27,040) 5 (1,27,043) 5 (1,27,040) 5 (1,27,040) 5 (1,27,043) 5 (1,27,040) 5 (1,27,043) 5 (2,208) 5 (1,27,043) 5 (2,208) 5 (1,27,043) 5 (2,208) 5 (1,27,043) 5 (2,208) 5 (1,27,043) 5 (2,208) 5 (1,27,043) 5 (2,208) 5 (1,27,043) 5 (2,208) 5 (1,27,043) 5 (2,208) 5 (1,20,224) 1 (1,20,224) 1 (1,20,224) 1 (1,20,224) 1 (1,20,224) 1 (1,20,224) 1 (1,20,224) 1 (1,20,224) 1 1 1 1 1 1 1 1 1 1 1 1	Adjustment for sales tax refund		R01		120.391 5	21.803 \$	23 030	11 043 6	, 1
Menti or reason 0.0ALL (5.277,336) 5 (1,710,617) 5 (774,006) 5 Trent for management for management audit fee 0.0MPT (5.205,82 5 3.2364 5 (132,043) 5 (74,006) 5 Trent for management audit fee 0.0MPT (76,038) 5 (132,043) 5 (52,035) 5 (132,043) 5 (52,035) 5 (132,043) 5 (52,035) 5 (132,043) 5 (52,035) 5 (142,023) 5 (142,023) (1,120,224) (1 (1,120,224) (1 (1,120,224) (1 (1,120,224) (1 (1,120,224) (1,120,23,54) (1,120,23,54) (1,120,23,54) (1,120,23,54) (1,120,23,54) 10,114 (1,120,23,54) (1,120,23,54)	Adjustment for OMU Nox expense		PLPPT		1,959,879 \$	399,862 5	330,153 \$	\$ 010 181 \$	124
Martin transminicture 0MT 153,982 32,366 32,354 13,666 5 Therrit for Reinsement audit fee 0MT 153,982 5 13,666 5 13,666 5 Therrit for Reinsement audit rectificant River Units 1 & 2 0MFPT (705,035) 5 (13,554) 5 (13,268) 5 (13,268) 5 (12,731) 5 (12,731) 5 (12,731) 5 (12,731) 5 (12,731) 5 (1,120,224) (1,120,234) (1,120,234) (1,120,234) (1,120,234) (1,120,234) (1,120,234) (1,120,234) (1,120,234) (1,120,234) (1,120,234) (1,120,234) (1,120,234) (1,120,234) (1,120,234) (1,120,	Adjustment for tee storm		SDALL		(5,277,336) \$	(1,874,536) \$	(1.710,617) \$	(774.008) \$	0,120 (6,178)
Adjustment of Green Kiver Units 1 & 2 OMPPT (705,035) \$ (113,554) \$ (127,043) \$ (52,036) \$ Instruction and Surrordit VDTREV (766,280) \$ (13,554) \$ (127,043) \$ (52,036) \$ Adjustments (61,610) \$ (61,620) \$ (61,620) \$ (127,043) \$ (52,036) \$ Adjustments (35,904,710) \$ (5,326,614) \$ (5,731,622) \$ (1,20,224) \$ (1,20,224) \$ Expenses TOE \$ 633,180,928 \$ 125,499,010 \$ 126,021,005 \$ 59,046,633 \$ 1,5 Expenses TOE \$ 60,289,011 \$ (37,0319) \$ 8,116,680 \$ 6,194,633 \$ 1,5 Adjustred) \$ \$ 50,046,633 \$ 126,021,005 \$ 59,046,633 \$ 1,5 Expenses TOE \$ \$ 60,289,011 \$ 176,021,105 \$ 6,194,637 \$ 1,5 Adjustred) \$ \$ \$ \$ \$ \$ 304,567,081 \$ 6,194,637 \$ 1,5 Adjustred) \$ \$ \$ \$ \$ \$ \$ 1,412,033,543 \$ 2,5 Adjustred) \$ \$ \$ \$ \$ \$ \$ 2,67%,45 2,67%,45 2,67%,45	Adjustment for management aucht fee		OMT		163,982 \$	32,806 \$	32,354 \$	13.868 \$	436
Adjustments VD MEV (466,280) \$ (5,364,47) \$ (38,856) \$ (4,120,224) \$ Adjustments (3,326,614) \$ (5,791,522) \$ (1,120,224) \$ (1,120,224) \$ Exponses TOE \$ 533,160,928 \$ 125,499,010 \$ 126,021,005 \$ 59,046,633 \$ 13 Exponse 5 60,289,011 \$ (370,219) \$ 8,116,680 \$ 6,194,817 \$ 8 1 noome (Adjusted) 5 50,046,633 \$ 14,12,033,543 \$ 360,876,204 \$ 304,587,081 \$ 160,366,344 \$ 2 Base 4,27% -0,11% 2,67% 366,376 \$ 2 2	Adjustment for Retrement of Green River Units 1 & 2 VDT A modification and Sumrodia		OMPPT		(705,035) \$	(119,554) \$	(127,043) \$	(52,038) \$	(2,079)
Constraint (3:596,614) (5,731,622) (1,120,224) (Expenses TOE \$ 533,160,928 125,499,010 5 59,046,533 13 Expenses TOE \$ 533,160,928 125,499,010 5 59,046,533 13 Roome (Adjusted) \$ 60,269,011 (370,219) 8 8,116,590 6 ,194,817 5 Base \$ 1,412,033,543 \$ 350,376,204 \$ 304,587,081 \$ 160,356,384 2,21 Base \$ 4,27% -0,11% 2,67% 3 8,62	Total Evinence Adjustments		VUIREV		(466,280) \$	(84,947) \$	(88,836) \$	(42,731) \$	(1,661)
Expenses TOE \$ 53,180,928 \$ 126,021,005 \$ 59,046,533 \$ 1,1 nome (Adjusted) \$ 60,269,011 \$ 1370,219) \$ 8,116,690 \$ 6,194,817 \$ 1 nome (Adjusted) \$ 1,412,033,543 \$ 350,376,204 \$ 304,587,081 \$ 160,356,384 \$ 2,1 Base \$ 4,27% \$ 0,11% \$ 2,47% \$ 0,11% \$ 2,67% \$ 3,66,366,384 \$ 2,2					(35,904,718)	(5,328,614)	(5,791,622)	(1,120,224)	(130,970)
ncome (Adjusted) \$ 60,263,011 \$ (370,219) \$ 8,118,690 \$ 6,194,817 \$ 6 \$ 1,412,033,543 \$ 350,876,204 \$ 304,587,081 \$ 160,356,384 \$ 2,8 Base 0,11% 2,67% 3,645 \$ 356,364 \$ 3,856,364 \$ 2,856,364 \$ 2,856,365,365,365,365,365,365,365,365,365,3	Total Operating Expenses	TOE		•	633,180,928 \$	125,499,010 \$	126,021,005 \$		1,928,089
Base \$ 1,412,033,543 \$ 350,876,204 \$ 160,356,384 \$ 2,1 1 4,27% -0,11% 2,67% 3,86%	Net Operating Income (Adjusted)			••	60,269,011 \$	(370,219) \$	8,118,690 \$	6,194,817 \$	651,183
	Net Cost Rate Base			Ś	1,412,033,543 \$	350.876.204 \$	304 587 081		199 199 5
4.27% -0.11% 2.67% 3.86%									400 ¹ 100'7
	Rate of Return	ļ		_	4.27%	-0.11%	2.67%	3.86%	22.60%

Summer CP Prod Trans Allocation All other KTUC Corrections Included

Exhibit (SJB-5) Page 5 of 8

12 Months Ended September 30, 2003

Description Ref Na	Name	Allocation Vector	Power	Power LPS	Power	Power LPT	TOD Primary LCIP	TOD Transmission LCIT	Secondary HLFS	Primary Hi FP
Operating Expenses										
Operation and Maintenance Expenses			ŝ	120,695,298 \$	26,982,414 \$	408,746	5 4,156,947	14.732.940	5 9 941 D01	\$ 18 624 035
Depreciation and Amortization Expenses				16,657,830	3,365,392	51,650	6,123,938	1,282,070	1,117,719	2,013,840
лединакију отебны ана Асасарол Ехрепсез Реодећу Тахеа		TON		(2,072,286)	(453,797)	(7,649)	(833,517)	(191,215)	(147,943)	(275,265)
Other Taxes				1,000,078	517,801 223,002	4,906	5/8,614 406 015	121,823 86 APT	105,434 73 084	190,324
Gain Disposition of Allowances				(58,459)	(14,367)	(217)	(29,956)	(8.707)	(5.503)	(10.413)
State and Federal Income Taxes		TXINCPF	•	10,520,722 \$	2,740,138 \$	84,027	3,960,476	1,738,363	\$ 797,227	\$ 1,487,812
opecnic Assignment of Curraliable Service Alder Credit Allocation of Curraliable Service Pider Credite		0.0	•	- 001 000 F	(181,381)		(271,654)	(499,037)	,	•
		202	•	\$ ASN'/AN'L	240,238 \$	4,049	441,260	101,228	\$ 78,321	\$ 145,724
Adjustments to Operating Expenses:		1								
cuitiniate mismaich in tuei cost recovery Remnive FCR exnerses		Energy	•••	(7,511,155) 5	(1,845,959) \$	(27, 879)	(3,848,951) \$	(1,118,710)	(202,007)	\$ (1,337,916)
Eliminate brokered sales expenses		Freedow	•••	(50,050) \$	(12,009) 5 (1442 570) 4	(193) (21 787)	(23,825) \$	(5,834) (974 340)	(4,435)	5 (8,322)
Eliminate DSM Expenses		DSMREV	• • •	(98,559) \$	(12.138) \$	(473)		- (a+7'+10)	(iic'zec) 5	(1,040,004)
Year and adjustment		YREND	5	(360.354) \$	71,010 \$	164,672		1		\$ (324,056)
Leprecianon agusment			5	- 7	•	•		'		
Labor adjustment				394,1/8 \$	79,636 5	1 222	144,912 5	30,338	26,449	5 47,654
Medical Expense (See Functional Assignment)			•	¢ 077'/01	t CD7'00	494	07'703 3	14,605	11,690	\$ 21,090
Adjustment for pension/post retir benefit (See Functional Assignment)		LBT	••			,				, ,
Storm damage adjustment		SDALL	÷	(42,357) \$	(5,656) \$,	\$ (8,718) \$,	(2,245)	(3,009)
curringte advertsing expenses (See Functional Assignment) Adjustment for sum dission of EFM and and another and		REVUC		• • •		, !	1	•		
Aujusti rein for americauph or goon augit expanse Amortization of rate case expenses		R01		13,383 5	3,000 5	45	5,608 \$	1,588	1,047	5 1,969
Remove Amortization of one-utility costs (See Functional Assignment)		LBT				C07 -		204 ⁰	0,363 1	1,963
Adjustment for injunes and damages account 925 (See Functional Assignment)	Ê	OMT	• ••	, ,	***					• •
Adjustment for VDT net savings to shareholders		LBT	••	540,895 \$	36,097 \$	1,392	179,877 \$	42,195	33,774	5 60,929
Adjustment for merger savings		LBT		3,544,093	629,656 \$	9,118	1,178,601 \$	276,473	221,295	\$ 399,222
Adjustment for MISO schedule 10 expenses		LG I PI TRT	~ ~	2014,415)	(90,505) \$ 44 213 \$	(1.311)	(169,408) \$	(39,739)	(31.808)	57,383)
Adjustment for effect of accounting change		DET	, vi	1.589,814 \$	321.191	4.929	584 465 5	122 360 1	14,414	20,019 102,000
Adjustment for IT staff reduction		LBT	\$	(112,417) \$	(19,972) \$	(289)	(37,385) \$	(8,770)	(7.019)	5 (12.663)
Adjustment to remove Alstom expenses		PLPPT	*	(748,612) \$	(163,934) \$	(2,763)	(301,107) \$	(920'69)	(53,444)	\$ (99,439)
Adjustment for corporate lease expense Adjustment for release tex menod		LBT 201	•	• • • •	•••••	, ;				
Adjustment for OMU Nax expense			~ v	4 070'/7	5 281'G		2 9/9/11 1 4 002 555	3,278	2,161	4,064
Adjustment for ice storm		SDALL		(472.573) 5	(63.098) 3	701	(108425) \$	45,64	03,497 (25 051)	52,325 555)
Adjustment for management audit fee		OMT	•	36,069 \$	8,064 \$	122	16,184 \$	4.403	2.971	5 5566
Adjustment for Retirement of Green River Units 1 & 2		OMPPT	•	(167,673) \$	(40.184) \$	(622)	(81,707) \$	(22,806)	(14,913)	\$ (28,135)
VULLAINORIZATION and Surcredit Total Exmanse Adjustments		VDTREV	•	(106,432) \$	(23,944) \$	(363) 1	(44,478) \$	(12,752) \$	(8.271)	\$ (15,454)
				(B, 5/4, 354)	(2,308,377)	129,136	(5,144,679)	(1,586,310)	(946,348)	(2,131,697)
Total Operating Expenses	щ		ŝ	140,530,471 \$	30,911,062 \$	678,091	59,387,445 \$	15,776,639 \$	11,013,892	\$ 20,177,910
Net Operating Income (Adjusted)			•	19,799,048 \$	4,950,846 \$	140,753	7,428,444 \$	2,958,424 \$	1,470,078	\$ 2.728.782
Net Cost Rate Base			ŝ	259,564,825 \$	51,991,165 \$	784,972	94,900,421 \$	19,860,683	17,404,133	\$ 31,259,117
Rate of Retrin			ļ		1 2 2 2 2 2 2					

Exhibit (SJB-5) Page 6 of 8

> Summer CP Prod Trans Allocation All other KJUC Corrections Included

KENTUCKY UTILITIES Cost of Service Study Class Allocation 12 Months Ended 12 Months Ended September 30, 2003

D			Coal	Coal Mining Power Primary	Coal Mining Power Transmission	Large Power Mine Power TOD Primary	Large Power Mine Power TOD Transmission		Combination Off- Peak
Operating Expenses	Ker Name	e Vector		ddW	TeM	LMPP	LMPT		CWH
Operation and Maintenance Expenses			•	3,348,701	\$ 2,845,493	5 1,435,379	ю́ 9	54 \$	1,197,352
Perilation And Annual Adda Contractor Expenses				383,454	293,871	151,005	.,	0	289,103
regulacity dictuits and Accretion Expenses				(49,867)	(43.573)	(19,206)		6	(9,331)
Cippeng Takes		NPT		36,135	27,913	14,212		53	26,081
Cain Dismostifier of Allowerson				25,356	19,587	9,973		ĝ	18,301
Ctate and Endered Income Turners				(1.839)	(1,608)	(810)		(26	(193)
Grae and Foueral Intorne Laxes Snarrific Assimment of Curtaitable Consi∕on Dides Condi		TXINCPF	\$	585,697	409,736	\$ 190,256	\$ 415,392	32 \$	(460,488)
Operation of Curtailable Service Rider Credits		SCP	-	26 400	, 23 067	- 10 168	, 10 110	•	
		1	•				•		
Adjustments to Operating Expenses:									
Eliminate mismatch in fuel cost recovery		Energy	**	(236,347)	(206,595)	\$ (104,115)	(243.795)	3 5) 3	(24.816)
Kernove ECR expenses		ECRREV	ŝ	(1,810)	(1,443)	5 (696)		3 (C	(156)
Eliminale Drokered sales expenses		Energy	5	(184,700)	(161,450)	\$ (81,363)	5 *	\$ (E	(19,393)
		DSMREV	•7	,		•	, ≎	ŝ	•
t car one aglustment Decretisting adjustment		YREND	م	(141,450)	(165,932)	,	\$ (424,256)	\$ (9)	(13,589)
beprevious aujusurent Adinetment for shanna in donovainting mus			••				••	••	•
Labor adjustment			•••	8 4/0 8	6,954	3.573	\$ 8,725	••• •••	6,841
Medical Expense (See Functional Assimoment)		9	•	2 NOR'S	3,Ub2	5 1,64U	3,72	6	4,326
Adjustment for pension/post refit benefit /See Functional Assimment)	(Juent)	1 B.T	•	•				•	
Storm damage adjustment	(man)	SDALL	• •	- (BAC)	•		•	•	10 6601
Eliminate advertising expenses (See Functional Assignment)		REVUC	• •4	(nne)		(060) ·	, , , , , , , , , , , , , , , , , , ,	~ u	(000,5)
Adjustment for amortization of ESM audit expense		ROI		430 3	344	5 166	5 F	с	. 37
Amortization of rate case expenses		OMT	*	2,151 \$	1,828	\$ 922	2.184	-	769
Remove Amortization of one-utility costs (See Functional Assignment)	inment)	LBT	ŵ	. '				- 4-9	! .
Adjustment for injuries and damages account 925 (See Functional Assignment)	inal Assignment)	OMT	ŝ		•			- 43	1
Adjustment for VUI net savings to shareholders		LBT	••	11,498 \$	8,846	\$ 4,738	\$ 10,757	\$	12,499
Adjustment for merger savings		LBT	••	75,341 5	57,959	\$ 31,045	\$ 70,48	4	81,898
Adjustment for this or extended a 10 expenses		LBT St tor		(10,829)	(8,331)	\$ (4,462)	\$ (10,131)	s	(11,772)
Adjustment for affect of screening to cypenses			., .	4,858 5	4,245	5 1,871	5.34	*	608
Adjustment for IT staff reduction			•	4 (190,05)	28,047	5 14,412	5 35,190		27,592
Adjustment to remove Alstom expenses		PI PDT	• •	+ (nec 7)	(1,030)		(1230)		(865.2)
Adjustment for corporate tease expense		L L	• •		(247,01)	(occ'o) (o'coo)			(1) 2(1)
Adjustment for sales tax refund		19		, 8 8 8 8 8			*	4 6 F	' Ł
Adjustment for OMU Nox expense		PI PPT		11 291	0 REG		40 04/	÷ •	2776
Adjustment for ice storm		SDALL		(9.598)			•		2113 (30 676)
Adjustment for management audit fee		IMO		1.001	850	(111-1-) S	 1016	••	(C/O'SC)
Adjustment for Retirement of Green River Units 1 & 2		OMPPT	- 47	(4,993)	(4.364)	S 1491	(E 21)		009)
VDT Amortization and Surcredit		VDTREV	\$	(3.381) \$	(2.696)	(1 2 9 1) S	5 (3.16) (3.16)		(286)
Total Expense Adjustments				(457,264)	(445,682)	(143,317)	(749,746)	`@	17,608
Total Operating Expenses	TOE		ŝ	3,896,772 \$	3,128,805	\$ 1,647,660	\$ 3,467,710	*	1,083,372
Net Operating Income (Adjusted)			•	985,539 \$	695,476	\$ 325,797	\$ 722,007	57	(650,270)
Net Cost Rate Base				5.981.173	4 510 623	5 73.597	5 5.40 885	. 4	4 738 100
								•	171 'no 1'r
Kate of Ketum				15,48%	15.42%	13.73%	12.80%	8	702 25-

Exhibit (SJB-5) Page 7 of 8

Summer CP Prod Trans Allocation All other KJUC Corrections Included

12 Moaths Ended September 30, 2003

Description	ļ	Allocation	All Elc	All Elcetric School	Electric Space Heating Rider	Water Pumping	- Duite	Decorative Street Private Outdoor Lighting Lighting		Customer Outdoor Lighting	Special
xpenses		VECTO		700	55	ε	21	Dec St Lt	PO Lt	001	Contracts
Onersting and Maintenance Evenence											
Depreciation and Amortization Expenses			•	3,328,612 5	621,342	\$ 605,136 477,585	\$ 3,219,253 \$	312,394 \$	2,630,668	5 416.377 5	13,911,603
Regulatory Credits and Accretion Expenses				(72 276)	(12,396)	(11,750)	101 001	/041'/07	212,141	\$ 209'BLL	2,095,125
Property Taxes		N₽T		58,968	10,619	12,713	153,788	18.476	65.883	10.622 \$	198,203
Other laxes				41,378	7,451	8,921	107,913	12,965	46.230	7.453 \$	139.485
Gain Disposition of Allowances				(1,496)	(257)	(254)	(601)	(34)	(833)	(145) \$	(6.918)
State and redetat income laxes		TXINCPF	••	52,369 \$	(14,881)	\$ (3,961)	\$ (231,071) \$	58,013 S	1,012,992	\$ 125,405 \$	887,604
operation of Curtaitable Service Rider Credit Allocation of Curtaitable Service Didor Pordat				•	• •	•	•		,		(3,630,403)
		sch	\$	38,263 \$	6,563	\$ 6,225	· ·	, ,	'	•	161,576
Adjustments to Operating Expenses:											
Eliminate mismatch in fuel cost recovery		Enerov	-	3 (112 241)	(32 067)	(22 K20)	CTT 0811 4	. 1171 C			
Remove ECR expenses		ECRREV	,	(1.423) 5	(232)	(562)	(107'1) *		(118,603) 1	(110,01)	(506,621)
Eliminate brokered sales expenses		Energy		(150,209) \$	(25,763)	(25.499)	5 (60.394) S	(3.452)	(127'7)	(14 544) •	(600 502) (604 505)
Eliminate DSM Expenses		DSMREV	•7				5		(000)		
Year end adjustment		YREND	\$	د. ۱	(11,965)		5 10,181 5	7,379 \$	43,060	(11.571) \$	
			*7	•	•	, ,			. ,		,
Aujustitizant for change in depreciation fale		DET	۰× ۱	14,907 \$	2,691	\$ 3,256	\$ 40,942 \$	4,919 \$	17,539	2,828 \$	49,577
Ladinal Evnaces (Cas Exactional Assignment)		L B I	•	5,517 \$	1,193	\$ 1,266	19.138 3	2,204 \$	9,677	i 1,556 \$	17,905
Adjustment for pension/bost ratio benefit (See Functional Ascimment)		ta i		•						~	ı
Storn damage adjustment			••		, .			- ה	•	•	•
Eliminate advertising expenses (See Functional Assignment)		REVUC	م ب	e (cac'z)	(700)	1 (1,032)	5 (3,854) 5	(302) \$	(4,091)	\$ (623) \$	(912)
Adjustment for amortization of ESM audit expense		R01	• •	are	. 5			* •	,]		
Amortization of rate case expenses		OMT		2.138 \$	399	385	2 0168 4	200 2010	1500	267 6	1,412
Remove Amortization of one-utility costs (See Functional Assignment)		LBT		•				, ,	· ·	, ,	002'0
Adjustment for injuries and damages account 925 (See Functional Assignment)	ent)	OMT	••	-				• • • •			• •
Adjustment for VOT net savings to shareholders		LBT	••	15,938	3,447	\$ 3,657	55,291 5	6,367 \$	27,956	4.495 \$	51.727
Adjustment for merger savings		LBT	••	104,430 \$	22,586	\$ 23,959 (5 362,283 \$	41,720 \$	183,175 5	29,452 \$	338,928
Adjustment for merger amornization expenses Adjustment for MISO schodulo 40 success		LBT	47 •	(15,010) \$	(3,246)	5 (3.444)	(52,073) \$	\$ (266'5)	(26,329) \$	(4,233) \$	(48,716)
Augustimatic for affact of accounting of expenses			. ,	7 042	1,208	1,146	-	• •			29,736
Adjustment for IT staff reducting cliange Adjustment for IT staff reduction			•	60,124	10,854	5 13,131 3	5 165,128 \$	19,839 \$	70,741 5	11,405 \$	199,958
Adjustment to remove Aistorn examises			~ ·	(3,312)	(116)	(/60)	(11,491) \$	(1,323) \$	(5.810) \$	(834) \$	(10,751)
Adjustment for corporate lease expense		LBT		* (ni i nz)	(01++)	(0+7'+) · · · · · · · · · · · · · · · · · · ·	• •			•	(110,257)
Adjustment for sales tax retund		R01		698	120	- + - + - + - + - + - + - + - + - + - +		* * * * • * *		, ,	
Adjustment for OMU Nox expense		ргррт	• •••	16.365 \$	2.807	2 7 667	• • •	÷.		* 701	21 2,2
Adjustment for ice storm		SDALL	5	(28,599) \$	(6, 163)	(11,514)	(43.003) \$	(3.368)	(45 64 1) 3	(7 132) \$	(10 180)
Adjustment for management audit fee		OMT	ŝ	886 \$	186	181	962 \$	93 5	786 5	124 5	4 157
Adjustment for Retirement of Green River Units 1 & 2		OMPPT	~	(4,646) \$	(187)	\$ (677) \$	5 (1.332) \$	(76)	(2,066) \$	(321) \$	(20,948)
VUT Amontization and Surcredit		VDTREV	••	(2,682) \$	(445)	\$ (490) \$	5 (3.643) \$	(222)	(4,383) 5	(630) \$	(12,760)
				(198,275)	(41,777)	(30,821)	402,384	63,148	52,110	(8,577)	(1,030,452)
Total Operating Expenses	TOE		÷	3,877,516 \$	690,396	\$ 723,785	5,381,845 \$	672,829	4,548,162 \$	670,638 \$	12,421,193
Net Operating Income (Adjusted)				215,552 \$	1,337	\$ 22,959 1	t (4,622) \$	131,676 \$	1,712,280 \$	217,613 \$	1,822,820
Net Cost Rate Base			•7	9,812,655 \$	1,781,871	\$ 2,206,421	i 30,099,258 \$	3,612,804 \$	13,031,725 \$	2,083,315 \$	31,694,458
Rate of Retrict			ļ								
				Z.ZU7	0.05%	1.04%	-0.02%	3.64%	13.14%	10.45%	5.75%

Exhibit (SJB-5) Page 8 of 8

Summer CP Prod Trans Allocation All other KIUC Corrections Included

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

IN THE MATTER OF:

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

EXHIBIT (SJB-6)

KENTUCKY UTILITIES Cost of Service Study Class Allocation 12 Months Ended September 30, 2003

Description	Ref	Name	Allocation Vector	Total System	Residential Rate RS	All Electric Residential Rate FERS	General Service Secondary GSS	General Service Primary GSP
Cost of Service Summary ~ Pro-Forma								
Operating Revenues								
Total Operating Revenue Actual			~	768,801,159 \$	137,916,946 \$	147,101,217	\$ 69,475,900	2.821.048
Pro-Forma Adjustments: Eliminate unbilied ravenue			60	• 000 310				
Adjustment for Mismatch in fuel cost recovery			Eneror	0/0/00 \$	122,243 5	129,125	61,916 3	2,528
Adjustment to Reflect Full Year of FAC Roll-in		FACRI	IR	1.417.623 \$	(a,rza,zri) 3 181543 S	(921,080,0) 182,126,0	(2,393,685) 3 06 001	(109,346)
Adjustment to set and support of the set of		ECRREV		(25,039,979) \$	(4,562,377)	(4.715.925)	30,331 3 (2.291.842) 3	4,703 (1531)
Remove off-streton EAD minimum.		ECRRI		17,986,813 \$	3,208,163 \$	3,428,757	1.647,196	66.930
Filminate hrukarod salas			PLPPT	(776,418) \$	(131,620) \$	(168,052)	(71,062) \$	(2.574)
Eliminate ESM revenues collected			Energy	(22,575,669) \$	(3,600,306) \$	(4,145,611) \$	5 (1,505,781) \$	(68,786)
Eliminate ESM.FAC.ECR from rate refund and		ESMKEV	100	(4,604,742) \$	(915,119) \$	(611,110)	5 (428,633) 5	(15,263)
Eliminate DSM Revenue		100Mac	עמו	1,530,747 \$	295,220	311,841	149,529 \$	6,105
Year end adjustment		VORMER		(2,942,935) \$ 55,455 5	(1,508,819) \$	(1,089,604)	5 (222,733) 5	(10,743)
Memer savinus				251,167	(417,181) \$	1,771,704	815,724 \$	•
Adjustment for rate switching, increased interruptible credit		RATESW	KUI	(2.564,269) \$	(464,390) \$	(490,535)	35,213) \$	(8,603)
VDT Amortization and Surcredit			VDTREV	85,337 \$	15,547 \$	16,258	7,821 \$	304
Total Pro-Forma Operating Revenue			(13,500,374) \$	693,449,939 \$	124,416,572 \$	135,130,054	65,106,127 \$	2,593,777

12 Munths Ended September 30, 2003

Description	Ref	Name	Allocation Vector	Combined Light & Power LPS	Combined Light & Power LPP	Combined Light & Power LPT	Large Commlind TOD Primary LCIP	Large Commlind TOD Transmission LCIT	High Load Factor Secondary HLFS	High Load Factor Primary HLFP
Cost of Service Summary – Pro-Forma										
Operating Revenues										
Total Operating Revenue – Actual				\$ 177,182,345	\$ 39,859,272	\$ 604,255	\$ 75,166,649	\$ 21,271,791	\$ 13,996,432	\$ 26,330,971
Pro-Forma Adjustments:										
Eliminate unbilled revenue Adjustment for Mismatch in fuel cost recovery			R01	\$ 154,859	-	\$ 526	5 64,896	ø	\$ 12,117	\$ 22.783
Adjustment to Reflect Full Year of FAC Polluin			Energy	5 (8,518,255)	\$ G	5 (31,617)	\$ (4,365,021)	ت به	\$ (801,803)	\$ (1,517,304)
		NOAT NUCCONT		\$ 365,749	\$	••	\$ 194,737	••	\$ 53,661	\$ 62.851
Adjustment to reflect Full Year of FCR Politin				\$ (5,734,057)	(1,290,905)	*	\$ (2,401,012)	\$ (688,721)	\$ (446,972)	57
		בכאצו	500 F	4,133,949	. ,	د ه	\$ 1,735,487	\$9	\$ 316,548	\$ 606,165
Eliminate brokered sales				(1/3,813		<i>.</i> ,	5 (79,812)	••	5 (14,134)	••
Eliminate ESM revenues collected			Chergy	a (b,358,526			\$ (2,745,877)	*	\$ (504,385)	\$
Eliminate ESM.FAC.ECR from rate refund acct			501	(1,152,341)	5 (264,123)	•••	\$ (474,129)	5	\$ (89,283)	\$ (160,668)
Eliminate DSM Revenue		100MaQ		066'92'9		•	\$ 156,727	••	\$ 29.263	*
Year and adkitetment				3 (98,441)	~	\$		•		s
Merner savince		Y RENU		5 (597,774)	5	٠. ج	, ,	•		5 (537 561)
Adiustment for rate suitching increased into multi-			RUT	5 (588,297)		•••	\$ (246,535)	\$ (69,809)	\$ (46.031)	\$ (86.551)
VOT Amortization and Surradia		RAIESW		,	\$ (42,856)		\$ (64,186)	\$ (120,793)		
			VUIREV	\$ 19,479	•	\$ 66	\$ 8,140	\$ 2,334	\$ 1,514	\$ 2,828
Total Pro-Forma Operating Revenue			(13,500,374) \$	\$ 160,008,866	\$ 35,908,129	\$ 817,952	\$ 66,950,064	\$ 18,820,425	\$ 12,506,927	\$ 22,958,719

12 Months Ended September 30, 2003

n, 4004			
SCPICIE021 341, 2003			

Description	Ref	Name	Allocation Vector	Coal Mining Power Primary MPP	Coal Mining Power Transmission MPT	Large Power Mine Power TOD Primary LMPP	Large Power Mine Power TOD Transmission LMPT	Combination Off- Peak CWH
Cost of Service Summary – Pro-Forma								
Operating Revenues								
Totat Operating Revenue – Actual				\$ 5,660,987	\$ 4,559,871	\$ 2,216,475	\$ 5,425,560	\$ 508,911
Pro-Forma Adjustments:								
Eliminate unbilled revenue			R01	\$ 4,976	\$ 3,978	\$ 1,924	5 4.748	\$ 432
Adjustment for Mismatch in fuel cost recovery			Energy	\$ (268,036)	\$	\$ (118,074)	\$ (276,483)	•
Adjustment to Reflect Full Year of FAC Roll-in		FACRI		\$ 12,843	5	\$ 2,865	\$ 11,438	\$ 1,179
Remove ECR revenues		ECRREV		\$ (182,407)	1 5 (145,445)	5 (70,105)	\$ (172,666)	- s
Adjustment to reflect Full Year of ECR Roll-in		ECRRI		\$ 132,466	~	\$ 51,614	\$ 127,076	*
Remove off-system ECR revenues			PLPPT	\$ (5,613)	5	\$ (2,499)	\$ (5,403)	*
Eliminate brokered sales			Energy	\$ (168,612)	5	\$ (74,276)	\$ (173,926)	•
Eliminate ESM revenues collected		ESMREV		\$ (33,089)		5 (11,418)	\$ (28,011)	
Eliminate ESM,FAC,ECR from rate refund acct.			R01	\$ 12,018	•	\$ 4,648	\$ 11,466	•
Eliminate DSM Revenue		DSMREV		•				•
Year and adjustment		YREND		\$ (234,645)	(275,257)		\$ (703,778)	\$ (22,542)
Merger savings			R01	\$ (18,905)	•••	\$ (7,311)	\$ (16,037)	\$ (1,639)
Adjustment for rate switching, increased interruptible credit		RATESW						
VDT Amortization and Surcredit			VDTREV	\$ 619	\$ 493	\$ 236	\$ 579	\$ 52
Total Pro-Forma Operating Revenue			(13,500,374) \$	1) \$ 4,912,603	\$ 3,845,270	\$ 1,994,079	\$ 4,202,563	\$ 434,167

12 Munths Ended September 30, 2003

				i	•	Electric Space			Decorative Stree	Decorative Street Private Outdoor	Customer	
Description	Ref	Name	Allocation Vector	All Elc	All Elcetric School AËS	Heating Rider 33	Water Pumping M	Street Lighting St Lt	Lighting Dec St Lt	Lighting PO Lt	Outdoor Lighting C O Lt	Contracts
Cost of Service Summary – Pro-Forma												
Operating Revenues												
Total Operating Revenue Actual				•	4,492,389 \$	776,874	\$ 817,460	\$ 5,609,441	\$ 815,367	\$ 6,541,571	\$ 962,798	18,686,630
Pro-Forma Adjustments:												
Etiminate unbilled revenue			R01	**	3.911 \$	675	••	\$ 5,345			•	16,335
Adjustment for Mismatch in fuel cost recovery			Energy	5	(217,983) \$	(37,387)	\$	\$ (87,643)	••	••	\$ (21,	(1,007,994)
Adjustment to Reflect Full Year of FAC RolLin		FACRI	1	\$	9.719 \$	881	~	\$ (1.021)	**	••		45,82
Remove ECR revenues		ECRREV		*	(143,373) \$	(23,364)	\$	\$ (196,772)	ŝ			(691,95
Adjustment to reflect Full Year of ECR Roll-in		ECRRI		•	104.270 \$	17.741	*	\$ 144,134	-	••	••	493,73
Remove off-system ECR revenues			PLPPT	\$	(5,951) \$	(1,093)	(866) \$	\$ (498)	\$ (28)	(171)	•	(16,698)
Eliminate brokered sales			Energy	*	(137,125) \$	(23,519)	÷	\$ (55,133)	\$.,	(634.09
Eliminate ESM revenues collected		ESMREV	3	*	(21,999) \$	1,124	•	\$ (37,564)	₩	"		(133,59
Eliminate ESM,FAC,ECR from rate refund acct.			R01	\$	9,445 \$	1,630	•	\$ 12,909	\$	•	\$	39,449
Eliminate DSM Revenue		DSMREV		•	•••	. •	*	, ,	\$	"	~	
Year end adjustment		YREND			• • •	(19.849)	•	\$ 16,889	\$ 12.240	5	\$ (19,194) \$	
Merger savings			R01	•	(14,857) \$	(2,564)	\$ (2,722)	\$ (20,307)	\$ (3,001)	1 \$ (23,470)	••	(62,054)
Adjustment for rate switching, increased interruptible credit		RATESW						•				(2,777,732
VDT Amortization and Surcredit			VDTREV	•	491 \$	81	\$ 90	\$ 667	\$ 102	\$ 802	\$ 115 3	2,335
Total Pro-Forma Operating Revenue			(13,500,3	74) 5	4.078,936 \$	691.230	\$ 745,233	\$ 5,390,448	\$ 805.262	\$ 6.280.921	\$ 891.430	13,960,186
Fotal Pro-Forma Operating Revenue			(13,500,374) \$	74) 5	4,078,936 \$	691,230	•	5 5 390,448	\$ 805,262	•	\$	1,430 \$

Average 12 CP Prod Trans Allocation All other KIUC Corrections Included

12 Months Ended September 30, 2003 General Service General Service

penses Expenses on Expenses	Dar Mana							1	6 0 0 0
Operating Expenses Operation and Maintenance Expenses Depreciation and Amorication Expenses Regulatory Credits and Accretion Expenses Property Taxes Other Taxes		Vector		System	Rate RS	Rate FERS		GSS	185
Operation and Maintenance Expenses Depreciation and Amortization Expenses Regulatory Credits and Accretion Expenses Property Taxes Other Taxes									
Depreciation and Amortarilon Expenses Regulatory Credits and Accretion Expenses Property Taxes Other Taxes				548 701 300 E	105 660 558	*	4 50	45 623 478 \$	1 544 149
Regulatory Credits and Accretion Expenses Property Taxes Other Taxes			•	88.376.624	19.722.676			9.577.587	224,699
Property Taxes Other Taxes				(8.656,053)	(1 467 394)		58)	(792,250)	(28,699)
Other Taxes		NPT		8.211.450	1 813 418		88	883,896	21,153
				5,761,996	1,272,480		64	620,232	14,843
Gain Disposition of Allowances				(246,288)	(39,277)	(45,226)	26)	(16,427)	(150)
State and Federal Income Taxes		TXINCPF		26,916,596 \$	(728,540)	•	82) \$	3,125,711 \$	346,205
Specific Assignment of Curtallable Service Rider Credit				(4,582,475)					•
		scP	\$	4.582.475	934.980	\$ 771.944	45	449,462 \$	11,972
Adjustments to Operating Expenses:									
Eliminate mismatch in fuel cost recovery		Energy		(31,644,777) \$	(5,046,623)	\$ (5,810,987)	87) \$	(2,110,684) \$	(86,419)
Remove ECR expenses		ECRREV		(248,468) \$	(45,272)	\$ (46,795	95) \$	(22,742) \$	(806)
Eliminate brokered sales expenses		Energy		(24.729.742) 5	(3,943,832)	\$ (4,541,167	67) \$	(1,649,456) \$	(75.349)
Eliminate DSM Expenses		DSMREV		(2, 946, 471) \$	(1,510,632)	\$ (1,090,913)	13) 5	(223,001) \$	(10,756
rearend adjustment				151,410	(Z01,488)	\$ 1,068,UZY		4 A1'/40	•
				, 000 c		· • •	•••	4 LE3 366	
Aujustment for change in depreciation rate Labor adjustmant				2,031,270 4	248 151	* JUG,000 * 741 886	 	106.464 S	110°0
Medical Exnense (See Exactional Assimment)		3		* nun'700'i	101,042	*	,	 Lotion 	
arouxed Expense (eee t arouxed a segurant) Adjustment for nension/host ratic banefit (See Functional Assiminant)	ent)	IВТ		•			•	,	
	(mm	SDALL		(473.014) 5	(168.017)	s (153.325)	25) 3	(69.375) \$	(554)
Eliminate advertising expenses (See Functional Assignment)		REVUC			-		•••		
Adjustment for amortization of ESM audit expense		Rot		58.333 \$	10,564	5 11.159	59 5	5,351 \$	218
Amortization of rate case expenses		OWI		352,456	67,868	5 73,217	17 5	29,305 \$	392
Remove Amortization of one-utility costs (See Functional Assignment)	ent)	LBT				•	•0		'
Adjustment for injuries and damages account 925 (See Functional Assignment)	Assignment)	OMT				•	÷	.	•
Adjustment for VDT net savings to shareholders		LBT		2,895,000 \$	716,908	\$ 698,809	\$ 60	307,575 \$	6,568
Adjustment for merger savings		LBT		18,968,825 \$	4,697,374	\$	84 \$	2,015,316 \$	43,038
Adjustment for merger amortization expenses		LBT		(2.726,510) \$	(675,183)	٠ ٩	38) \$	(289,674) \$	(6.186)
Adjustment for MISO schedule 10 expenses		PLTRT		843,344 \$	142,966	•	37 \$	77,187 \$	2,796
Adjustment for effect of accounting change		DET		8,434,618 \$	1,882,322		\$ 60	914,080 \$	21,445
Adjustment for IT staff reduction		LBT		(601,682) \$	(148,998)	\$ (145,237)	37) \$	(63,925) \$	(1,365)
Adjustment to remove Alstom expenses		PLPPT		(3, 126, 995) \$	(230,095)	<i></i>	22) \$	(286,200) \$	(10,36)
Adjustment for corporate lease expense		LBT		••	•	•	•7	•	•
Adjustment for sales tax refund		R01		120,391 \$	21,803	\$ 23,030	30 \$	11,043 \$	451
Adjustment for OMU Nox expense		PLPPT		1,959,879	332,243	\$ 424,206	99 9	179,379	6,498
Adjustment for ice storm		SDALL		(5,277,336) \$	(1, 874, 536)	5 (1,710,617)	17) \$	(774,008) \$	(5,178)
Adjustment for management audit fee		DWT		163,992 \$	31,576	34,065	65 \$	13,634 \$	461
Adjustment for Retirement of Green River Units 1 & 2		OMPPT		(705,035) \$	(114,041)	5 (134,708	3 8) 2	(50,991) \$	(2,191)
VDT Amortization and Surcredit		VDTREV		(466,280) \$	(84,947)	\$ (53,836)	36] \$	(42,731) \$	(1,661)
Total Expense Adjustments				(35,904,718)	(5,775,189)	(5,170,648	48)	(1,205,074)	(121,875)
Total Operating Expenses	TOE		•	633,180,928 \$	121,393,711	\$ 131,729,540	40 \$	58,266,615 \$	2,011,697
Net Operating Income (Adjusted)			••	60,269,011 \$	3,022,861	3,400,514	14 \$	6,839,512 \$	582,080
Net Cost Rate Base			47	1,412,033,543 \$	321,541,172	\$ 345,378,280	80 \$	154,782,645 \$	3,479,092
R-460- 4			┝	1 1741	1940 V		1 000	1 1001	46 734
			-	4.41 74	8 # 0.'>			B 74-4	19191

Exhibit (SJB-6) Page 5 of 8

> Average 12 CP Prod Trans Allocation All other KIUC Corrections included

KENTUCKY UTILITIES Cast of Service Study Class Allocation 13 Months Ended September 30, 2003

Description	Ref Name	Allocation Vector	I	Power	Power LPP	Power LPT	TOD Primary LCIP	TOD Transmission LCIT	Secondary HLFS	Primary HLFP
Operating Expenses										
Oneration and Maintenance Excenses				11E EAD 760 .	77 349 611 C		6 100 D20 P3	10 200 21 4	10 073 257	19 014 270
Depreciation and Amortization Expenses			•		3.495.266	49.142	6 500 949			2,160,026
Regulatory Credits and Accretion Expenses				(1,937,791)	(473,184)	(7,274)	(889,795)	(227,019)	(157,572)	(297.087
Property Taxes		NPT		1,480,263	330,142	4,667	614,440	144,615	111,564	204,215
Other Taxes				1,038,704	231,662	3,275	431,154	101,477	78,285	143,25
Gain Disposition of Allowances				(58,459)	(14,367)	(217)	(29,956)	(8, 707)	(5,503)	(10,413)
State and Federal Income Taxes		TXINCPF	••	11,638,614 \$	2,578,996 \$	87,139 \$	3,492,699	1,440,764	717,195	5 1,306,431
Specific Assignment of Curtailable Service Rider Credit				•	(181,381)	•	(271,654)	(499,037)		•
Allocation of Curtailable Service Rider Credits		SCP	••	1,097,059 \$	240,238 \$	4,049	441,260	101,228	5 78,321	\$ 145,724
Adjustments to Docrating Expenses										
Filminate mismatch in fuel montant		C	•	(7 E44 4EC) ¢	(1 040 050) 0		20 0 0 0 0 0	- 101 01 11	(Loo tot)	- 740 P
Editoria de la sumera de la cuerta cuerta cuerta de la sumera de Sumera de la sumera de		Energy ECDDEL/	~ •	¢ (cci'iic'i)	<pre>(ACA'C+0'L)</pre>	(6/9',7)	(106/040/c)			(11.33/.910)
Eliminate brokered sales expenses		Fireme	• •	(5869.813) \$	(1 447 570) 5	(1282 1 <i>6</i>)	(120'07) (120'07)		(4,4.33)	277) (0,227) S
Eliminate DSM Expenses		DSMREV		(38,559) \$	(12,138) 5	(473)				
Year end adjustment		YREND		(360,354) \$	71,010 \$	164,672	,		•	5 (324.056)
Depreciation adjustment		DET	••				•		,	, ,
Adjustment for change in depreciation rate		DET	••	372,858 \$	82,709 \$	1,163 5	153,834	36,014 \$	27,975	\$ 51,113
Labor adjustment		LBT	**	182,122 \$	33,999 \$	467 \$	64,398	15,964	12,056	\$ 21,918
Medical Expense (See Functional Assignment)		1	•							
Adjustment for perision/past retir denemit (See Functional Assignment) Stam damate adjustment	(juqu			• (F36.07)	- L					
Eliminate adverticing exnences (See Functional Accimment)			••	(100'34)	* (aco'c)	•	(9L/'A)		(\$17.245)	(2,UUU) \$
Adjustment for amortization of ESM audit expense		R01	.	13.82 5		- 42 - 42	191	- 1 Kan	1 047	1 1 050
Amontization of rate case expenses		OMT	• ••	76.335 \$	17.503 \$	259	35.284	5 192 5	6.471	17 156
Remove Amortization of one-utility costs (See Functional Assignment)	nent)	LBT	*	. '					-	
Adjustment for injuries and damages account 925 (See Functional Assignment)	al Assignment)	OMT	5	•		•	, 43			
Adjustment for VDT net savings to shareholders		LBT	•7	526,150 \$	98,223 \$	1,350 \$	186,047 \$	\$ 46,120 \$	34,829	\$ 63,321
Adjustment for merger savings		181	•	3,447,476 \$	643,584 \$	8,849	1,219,030	302,193 5	228,212	\$ 414,89
Adjustment for merger amonization expenses				(485,528) \$	(92,506) 5	(1.272) 5	(175,219) \$	(43,436) \$	(32,802)	\$ (59,63
Adjustment for effect of scoredule to expenses				100,/90	40,102 \$		86,691	57, 118 811,22	15,352	5 28,94
Adjustment for IT staff adjustion			•			4 (DAU 4	020 441	140,202 5	112,651	
Adjustment to remove Alstom expenses		PI PDT	• •	4 (300,007)	(120'71')	(102) (102)	(100'0C)	(110 ca)	(502,1)	 (10,100) (10,100) (10,100)
Adjustment for corporate tease expense				5		(5		(n70'nn)	
Adjustment for sales tax refund		R01	5	27,620 \$	6,192 \$	946 1	11.575	3.278	2,161	\$ 4 064
Adjustment for OMU Nox expense		PLPPT	•	438,749	107,137 \$	1,647 5	201 465	51.401	35,677	5 B7 26
Adjustment for ice storm		SDALL	.,	(472,573) \$	(63,098) \$. '	(108,425) \$		(25,051)	\$ (33,56
Adjustment for management audit fee		ONT	••	35,515 \$	8,143 \$	121	16,416 5	4,550 5	3,010	\$ 5,656
Adjustment for Retirement of Green River Units 1 & 2		OMPPT	**	(165,191) \$	(40,541) \$	(615) 3	(82,745) 5	i (23,467) \$	(15,091)	\$ (28,53
VDT Amortization and Surcredit		VDTREV	ŝ	(106.432) \$	(23,944) \$	(363) \$	(44,478) \$	(12,752) 5	(8,271)	\$ (15,45
i otal Expense Adjustments				(9,175,410)	(2,279,396)	128,577	(5,060,548)	(1,532,786)	(931,953)	(2,099,076
Total Operating Expenses	TOE		÷	138,682,191 \$	31,177,487 \$	672,946 \$	60,160,849 \$	16,268,676 \$	11,146,215	\$ 20,477,798
Net Operating Income (Adjusted)			*	21,326,675 \$	4,730,642 \$	145,006	6,789,215 \$	2,551,749 \$	1,360,711	\$ 2,480,920
Net Cost Rate Base			•>	246,357,662 \$	53,894,949 \$	748,210 \$	100,426,897 \$	23.376,610 \$	18,349,567	\$ 33,402,015

Exhibit (SJB-6) Page 6 of 8

Average 12 CP Prod Trans Allocation All other KIUC Corrections included

12 Months Ended September 30, 2003

		Allocation	Coal	Coal Mining Power Primary	Coal Mining Power Transmission	Large Power Mine Power TOD Primary		Power TOD Transmission	Combination Off- Peak	ŧ
Description	Ref Name			МРР	MPT	LMPP		LMPT	CWH	
Operating Expenses										
Accordian and Maintenanan Economic			•	0 600 740	- 000 TB1		•		1 202	ŝ
Operation and Amortization Expenses			•	468.571	v	208.952	•	204 804 S	666 666	560 666
Regulatory Credits and Accretion Expenses				(62.573)	(52,377)	(27,856)	56)	(60,238)	6)	(178)
Property Taxes		NPT		44.223	33,517	19.719	19	38,459	26	26.365
Other Taxes				31,031	23,519	13,837	37	26,987	18	18,501
Gain Disposition of Allowances				(1,839)	(1,608)	(810)	10)	(1,897)		(193)
State and Federal Income Taxes		TXINCPF	\$	480.089	\$ 336,562	\$ 118,359	59 \$	371,609	1 (454	464,200)
Specific Assignment of Curtailable Service Rider Credit				•	•	•				
Allocation of Curtailable Service Rider Credits		scP	Ś	26,400	\$ 23,067	\$ 10,168	88 5	29,038	4	4,940
Adjustments to Operating Expenses										
Eliminate mismatch in tuel cost recovery		Energy	s	(236,347)	\$ (206.595)	\$ (104.115)	15) \$	(243.795)	5 (24	(24.816)
Remove ECR expenses		ECREV	\$	(1,810)	\$ (1,443)	(969) \$	96) \$	(1,713)		(156)
Elimínate brokered sales expenses		Energy	••	(184,700)	\$ (161,450)	\$ (B1,363)	53) \$	(190,521) 1	1 13	(19,393)
Eliminate DSM Expenses		DSMREV	\$	•		•	••	,	•	
Year end adjustment		YREND	\$	(141,450)	(165,932)	, ,	••	(424,256)	5 (13	(13,589)
Depreciation adjustment			~ ·			•	•••	• [. ;
Adjustment for change in depreciation rate				11,088	8,349	5 4,944	4 S			6.912
Labol aujusii eni Madimi Evranıs (Soa Evonional Anaimmaa)		9	^	4,402	025'5	, ,	*	072'0	4	c+c,
Meatent Expense (add Following Assignment) Adjustment for nencipations refit henefit (Cael Functional Assignment)		10 4	÷	,			·	ļ		
Storm damage adjustment	Burnerey		, ,	(360)			(305)		5	(1 556)
Eliminate advertising expenses (See Functional Assignment)		REVUC		(ana)					2	
Adjustment for amortization of ESM audit expense		R01		430	344		98	410		37
Amortization of rate case expenses		OMT	~	2,263	1,906	36	\$ 565	2,232		773
Remove Amortization of one-utility costs (See Functional Assignment)	(gnment)	LBT	5	•		•	.,			
Adjustment for injuries and damages account 925 (See Functional Assignment)	ional Assignment)	OMT	•	•		•	••	,		,
Adjustment for VDT net savings to shareholders		LBT	5	12,892	9,811	5,686	36 5	11,348	12	12,548
Adjustment for merger savings		LBT	•7	84,469	64,283	\$ 37,25		74,354	82	82,219
Adjustment for merger anvoltization expenses			•	(12,141)	5 (9.240)	5 (5,356)	s (j	(10,687)	E	(11,818)
		PCIN PCIN		6,096	501'G	5,01	**	R09'0	;	200
Adjustment for energion accounting change Adjustment for IT staff raduction				44,720 (3,670)		19,942		30,034 3	35	10 17
050SC		Pi PPT		(22 605)	(128 d)	(10.06	53) 5	(01 761) 1	10	532)
Adjustment for corporate lease expense		LBT		-			- 41		2	<u>.</u>
Adjustment for sales tax refund		R01	• • •	888	502 203	5 343	43 43	847		17
Adjustment for OMU Nox expense		PLPPT	•	14,168	\$ 11,859	\$ 6.307	07 S	13,639	2	2,214
Adjustment for ice storm		SDALL	ŝ	(8,598)		5 (4,411)	11) \$	'	3 (39	(39,675)
Adjustment for management audit fee		OMT	-	1,053	887	5 465	92 9	1,038		360
Adjustment for Retinement of Green River Units 1 & 2		TIMO	5	(5.227)	\$ (4,527)	\$ (2,30	\$ (80	(5,313)		(608)
VDT Amortization and Surcredit Total Eventse Adiustments		VOTREV	•	(3,381) (139.970)	(2,696) (427 E24)	(1,291) (1,291)	91) \$	(3,165) \$ (744 604)	- ¢	(286) 18 776
					(1 20'204)		Ís.		2	2
Total Operating Expenses	TOE		•	4,071,380	3,249,788	\$ 1,766,531	31 \$	3,541,753	1,089,511	511
Net Operating Income (Adjusted)			•	841,223	595,482	\$ 227,548	48 \$	660,810 \$	\$ (655	(655,344)
Net Cost Rate Base				7,228,861	5,375,126	\$ 3,223,008	08 S	6,169,967	\$ 4,781,983	983
										[
Rate of Return				11.64%	11.08%	7.06%	6%	10.71%	-13	13 70%

Exhibit _____ (SJB-6) Page 7 of 8

> Average 12 CP Prod Trans Allocation All other KIUC Corrections Included

KENTUCKY UTILITIES Cast of Service Study Class Allocation 12 Moaths Ended September 30, 2003

Description	Name	Allocation Vector	All Elce	All Elcetric Schoot F AFS	Heating Rider 33	Water Pumping M		ue Street Lighting St Lt	Lighting Dec St Lt	Lighting PO Lt	Outdoor Lighting C O Lt	Special Contracts
Xpenses												
Operation and Maintenance Expenses			••	3,246,942	618,434	5 596,400	400 \$	3,295,670 5	316,763	5 2,/49,015	5 434,/52	5 12'2/1'4/2
Uepreciation and Amonization Expenses				297,085	110,211	153,337	33/ 101	1,101,338		10/06/	104-071	770'167'1 4
Regulatory Credits and Accretion Expenses				(66,348)	(001,21)	Ē	(07)	(2) 24()	(317)	(06C'0)	(400°-1)	
Property Taxes		NPT		55,195	10,485	12	12,309	15/,319	18,6/8	105,17	1/4/11	166'771 \$
Uther laxes				38,730	165,1	το T	070	195,011	13,107	/onine	240,0	5 ·
Gain Disposition of Allowances				(1,496)	(257)		(254)	(601)	(98) 1	(823)	(145)	5 (6,918)
State and Federal income Taxes		TXINCPF	•>	101,641 \$	(13,126)	5	1 309 \$	(277,175) \$	55,377	\$ 941,592	114,319	\$ 1,877,108
Specific Assignment of Curtalitable Service Rider Credit					•				•	•	•	\$ (3,63(
Allocation of Curtailable Service Rider Credits		SCP	un.	38,263 \$	6,563	\$ 2	6,225 \$, ,	•	•		\$ 161,576
Adjustments to Operation Exnemene.												
			•	4 19 10 0017	120 002		• \003	4 (Fac 77)	17.14.17	¢ (110.002)	* /1P.611)	* /000 001.
		Energy	^ .	< (I LZ'ZAL)	(22,957)	(7c)	¢ (670'79)				(10'01)	
Remove DUR expenses		ECKKEV	<i>n</i> 4	(1,423) 3	(252)		* (707) * (707)	(102 09/	(167)	(007'700)	(1000) (200)	2 (0000) 2 (0001 605)
Climate provered sales expenses		Crently	•••	¢ (anz'nei)	(50) (57)	*	+ 100+		(7C+'c)	(000'00) *		**
Elitationate USM Expenses			* •	• •		•	••			43 050	2 (11 E74)	~ .
rear end adjustitient			* •	•	(coe'III)	•	••		201			••
Lepreciation adjustment			••								• • •	
Adjustment for change in depreciation rate Labor adjurtment				13,800 4	2,000	5 -	0,100 4	170'14	10 A C	10003	16.06	5 30,00
tabut aujustrisiit. Madinal Evenana 70an Erredianal Assimananti		9	•	* 767'F	20-	•			2	2000'n1		
weucer Expense (see runcuoral Assignment) Adjustment for nension/nost refit henefit (See Functional Assignment)		IRT		•• '		5	67 -			,		
Storm damage adjustment		SDALL		(2.563) 5	(552)	5 1	(1.032) 5	(3.854) \$	(302)	\$ (4.091)	\$ (639)	
Eliminate advertising expenses (See Functional Assignment)		REVUC					**	•				~
Adjustment for amortization of ESM audit expense		R01		338 \$	58		62 \$	462 \$	68	\$ 534	\$ 78	\$ 1,412
Amortization of rate case expenses		OMT	*	2,086 \$	397	•	383 \$	2,117 \$	203	\$ 1,766	\$ 279	•
Remove Amortization of one-utility costs (See Functional Assignment)		LBT	••	• •	ı		ب و ب	•••	•	,	, ,	s
Adjustment for injuries and damages account 925 (See Functional Assignment)	nment)	OMI	•	ب ور ا			*					
Adjustment for VDT net savings to shareholders			•	15,288 5	3,424		3,587 \$	55,899 5	6,402	2 2 2 B 8 9 8	5 4,641	5 38,6/5
			^ •	100°177	22,434	2		107'00C	047-14	40 103,540	014/02 P	••
Adjustment for MICO schedule 10 expenses			• •	(14,330) 3 6 A64 5	1 187	2 -	oroj 4	(072,040)	(670'n)	(01.2,12) 837	130.130	18 137
Adjustment for affect of accounting change				56 334 5	10 7 19	12	12.726 \$	168.674 \$	20.041	s 76.233	5 12.258	
Adjustment for IT staff reduction		LBT		(3.177)	(712)		(746) \$	(11.618) \$	(1.331)	(6.006)	\$ (965)	
Adjustment to remove Alstorn expenses		PLPPT	- 67	(23,968)	(4.402)	5 (4)	(4,019) \$	(2.004)	(115)	\$ (3,103)	\$ (482)	•
Adjustment for corporate lease expense		LBT	60	• •			-					~
Adjustment for sales tax refund		ROt	\$	698 \$	120	~	128 \$	963 \$	141	\$ 1,102	5 162	••
Adjustment for OMU Nox expense		PLPPT	**	15,022 \$	2,759	5 2	2,519 \$	1,256 \$	72	\$ 1,945	\$ 302	\$
Adjustment for ice storm		SDALL	••	(28,599) \$	(6,163)	5 (11.	(11,514) \$	(43,003) \$	(3,368)	\$ (45,641)	\$ (7,132)	5 2
Adjustment for management audit fee		OMT	ŝ	\$ 0/6	185	•	178 \$	982 3	95	\$ 822	5 130	\$ 3,667
Adjustment for Retirement of Green River Units 1 & 2		OMPPT	ŝ	(4,537) 5	(283)	~	(768) \$	(1,434) \$	(82)	\$ (2,224)	5 (345)	3
VDT Amortization and Surcredit		VDTREV	\$	(2,682) \$	(445)		(490) 5	(3,643) \$	(557)	5 (4,383)	5 (630)	5 (12,760)
l otal Expense Adjustments				(751,137)	(42,093)	(31,	(31,753)	410,014	279'59	108'40	(505'0)	11,2002,11
Total Operating Expenses	TOE		\$	3,796,052 \$	687,494	\$ 715,072	072 \$	5,458,071 \$	677,187	\$ 4,666,211	\$ 688,967	\$ 10,785,185
Net Operating Income (Adjusted)			•	282,883 \$	3,735	\$ 30,	30,161 \$	(67,623) \$	128,075	\$ 1,614,710	\$ 202,463	\$ 3,175,001
Net Cost Rate Base			••	9,230,542 \$	1,761,139	\$ 2,144,158	158 \$	30,643,939 \$	3,643,943	\$ 13,875,266	\$ 2,214,289	\$ 20,004,120
											ſ	
Osta of Datum	i		Γ	1000 0	1944.0	•	4 440/	976.0	2 5142	A4 6400	0 441/	

Average 12 CP Prod Trans Allocation All other KJUC Corrections Included

Exhibit (SJB-6) Page 8 of 8

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

IN THE MATTER OF:

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

EXHIBIT (SJB-7)

				12 Months Ended September 30, 2003	ed 003				
Description	Ref Name	Allocation Vector		Fotal System	Residential Rate R	Water Heating Rate WH	General Service Rate GS	Rate LC Primary	Rate LC Secondary
Cost of Service Summary – Pro-Forma									
Operating Revenues									
Total Operating Revenue – Actual			€	768,525,785 \$	291,774,308 \$	1,042,105 \$	106,206,583 \$	8,933,859 \$	132,997,184
Pro-Forma Adjustments:		100	¥	(1 B67 000) \$	(715.724) \$	(2.428) \$	(271,251) \$	(21,339) \$	(322,331)
Eliminate unbilled revenue Mismotoh in fijal cost racovary		Energy	•		(1,479,166)	(6,691)	(513, 321)	(58,331)	(791,604)
Mishaudh in iudi cust recovery To Dodant o Duill Voor of the CAM Doillin	FACRI			547,241	181,639	1,202	87, 109	11.617	139,923
	FCRRI	2		(11,228,429)	(4,264,952)	(15,362)	(1,630,456)	(127,642)	(1,940,152)
To Beflect a Full Year of the FCR Boll-In	ECRRI			723,260	255,297	937	110,897	9,089	133,401
		PLPPT		(1,929,923)	(798,593)	(2,924)	(212,071)	(20,734)	(330,945)
Filminate brokered sales		Energy		(22,608,445)	(7,589,772)	(34,335)	(2,633,910)	(299,304)	(4,Ub1,B14)
Eliminate ESM revenues	ESMREV			(6,974,780)	(2,763,963)	(7.154)	(1,009,115)	(80,480)	(1,196,265)
Eliminate Rate Refund Acct		R01		(7, 150, 231)	(2,741,076)	(A67'A)	(1,038,033)	(01,120)	(004,PC2,I)
Eliminate DSM Revenue	DSMREV	Ē		(3.277,501)	(7,17,1,65/)	. 500 09	(100,824)	(070°72)	932 854
Year End Revenue Adjustment	YREND			2,614,34/	0/2'227'L	(000 C)		(31 532)	(476,296)
Adjustment for Merger savings		R01		(2, /58, /95)	(eec') cn'L)	(poc'c)			· · · · · ·
Adjustment for Customer Rate Switching & CSR Credit	RATESW			(621,927)		. 6	- 6 447	505	7.617
VDT Amortization and Surcredit		VDTREV		44,485	acr' / L	ic.			
Total Pro-Forma Operating Revenue			ы	709,631,942 \$	269,278,378 \$	952,526 \$	98,312,757 \$	8,208,359 \$	123,516,811

LOUISVILLE GAS AND ELECTRIC COMPANY Cost of Service Study Class Allocation

> BIP Prod Trans Allocation Removes ECR Rate Base Present Revenues reflect CSR incr CSR Credits allocated on SCP

Exhibit (SJB-7) Page 1 of 6

					12 Months Ended September 30, 2003	ed 003				
Description	Ref	Name	Allocation Vector		Rate LC-TOD Primary	Rate LC-TOD Secondary	Rate LP Primary	Rate LP Şecondary	Rate LP-TOD Transmission	Rate LP-TOD Primary
Cost of Service Summary Pro-Forma										
Operating Revenues										
Totai Operating Revenue – Actual				ŝ	14,652,107 \$	19,054,006 \$	6.245.422 \$	34,323,004 \$	16.876,390 \$	80,727,853
Pro-Forma Adjustments:			2	•	9 (063 FC)	(45 400) S	(14 766) \$	(83.348) \$	(37,178) \$	(183,683)
Eliminate unbilled revenue			KU† Eoerari	•		(118.786)	(42.016)	(212,910)	(138,932)	(601,261)
Mismatch in fuel cost recovery					16.117	24 738	5,030	28,206	10.866	20,692
To Reflect a Fuil Year of the FAC Roll-In					(207 809)	(275,776)	(89,065)	(505,167)	(223,730)	(1,130,594)
Remove ECR revenues					14 884	21,249	5,484	35,195	16,754	67,122
To Reflect a Full Year of the ECK Koll-In					(35 905)	(50.917)	(14,985)	(75,351)	(46,325)	(217,365)
Remove off-system ECR revenues			Frank		(504,933)	(609,504)	(215,588)	(1,092,466)	(712,877)	(3.085,143)
Eliminate brokered sales		CCM0D/			(130.047)	(164,826)	(53,219)	(301,827)	(135,771)	(645,195)
Eliminate ESM révenues			801		(132,469)	(173,873)	(56,551)	(319,207)	(142,383)	(703,468)
Eliminate Kale Kelunu Acct		DSMREV			(14,688)	(16,281)			,	,
		VBEND			1	566.077	T	147,900		
Year End Revenue Adjustment			R01		(51,111)	(67,086)	(21,819)	(123,161)	(54,936)	(271,421)
		DATESIA			. "	•		·	(279,699)	(877'797)
Adjustment for Customer Rale Switching & USR Oreun VDT Amortization and Surcredit			VDTREV		815	0/0/1	349	1.955	867	4,284
Total Pro-Forma Operating Revenue				63	13,473,965 \$	18,144,692 \$	5,748,275 \$	31,822,823 \$	15,133,047 \$	73,729,592

LOUISVILLE GAS AND ELECTRAC COMPANY Cost of Service Study Class Allocation

		Street Lighting Rate OL
		Street Lighting Rate SLE
LECTRIC COMPANY ce Study catiou	Ended 6, 2003	Street Lighting Rate PSL
LOUISVILLE GAS AND ELECTRIC COMPANY Cost of Service Study Class Allocation	12 Mouths Ended September 30, 2003	Rate LP-TOD Secondary
		Allocation Vector
		Ref Name
		Ref

Special Contracts

Street Lighting Rate TLE

Cost of Service Summary -- Pro-Forma

Description

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Operating Revenues									
Total Operating Revenue – Actual			÷n	2,667,730 \$	5,832,231 \$	207,928 \$	7.037,493 \$	727,497 \$	39,220,086
Pro-Forma Adjustments:									
Eliminate unbilled revenue		R01	69	(6.454) \$	(15 890) \$	(464) \$	(19.577) \$	(1 786) ¢	(00,707)
Mismatch in fuel cost recovery		Energy		(16 458)	(19 759)	(1 535)	(20, 526)	(A A10)	(20, '00)
To Reflect a Fuil Vear of the EAC Boiltin				(an-in-i			070,02	(n+t)	(550,033)
				1,430	(3,891)	156	(1.432)	197	23,036
Refrieve FOR fevenues	ECRREV			(40,296)	(98,342)	(3,010)	(121,526)	(11,097)	(543,453)
I O Mettect a Full Year of the ECK Roll-In	ECRRI			3,088	6,611	212	9.072	811	33,157
Remove off-system ECR revenues		PLPPT		(6,192)	(8,400)	(699)	(8,714)	(1.481)	(98.352)
Efiminate brokered sales		Energy		(84,446)	(101,383)	(7,875)	(105.321)	(22,630)	(1,447,143)
Eliminate ESM revenues	ESMREV			(20.232)	(57,193)	(1.416)	(65.875)	(6.308)	(335.874)
Eliminate Rate Retund Acct		R01		(24.719)	(60.854)	(1 778)	(74 974)	(F 841)	(347 716)
Eliminate DSM Revenue	DSMREV			. '				(110)	(n) 1' 1- (n)
Year End Revenue Adjustment	YREND				2.999	(1.159)	17.114	5 808	
Adjustment for Merger savings		R01		(8.537)	(23.479)	(EBE)	(28 028)	02202	(Dat KEt)
Adjustment for Customer Rate Switching & CSR Credit	RATESW			-		Innol	(201020)	(cro. 7)	(000 00/
VDT Amortization and Surcredit		VDTREV		146	364	10	453	41	2,148
Total Pro-Forma Operating Revenue			••	2,464,065 \$	5,453,014 \$	189.714 \$	6,617,260 \$	677,761 \$	35,908,904

BIP Prod Trans Allocation Removes ECR Rate Base Present Revenues reflect CSR incr CSR Credits allocated on SCP

Class Allocation 13 Months Ended

12 Months Ended September 30, 2003

Description Ref No	ла Пе	Allocation Vector		Total System	Residential Rate R	Water Heating Rate WH	General Service Rate GS	Rate LC Primary	Rate LC Secondary
Cost of Service Summary – Pro-Forma									
Operating Expenses									
Operation and Maintenance Expanses									
Depreciation and Amortization Exnerces			n	508,148.420 \$	ZD3,882,981 \$	1,176,453 \$	60,345,199 \$	5,773,024 \$	82,923,255
Accretion Expense				COR,128,CB	44,533,075	340.924	11, 122, 256	851,366	13,983,904
Property and Other Taxes		NOT		402,319 47 603 252	191,386	10/	50,824	4,969	79,313
Amortization of Investment Tax Credit				12,000,000 h	0,000,040	42,776	1,456,554	113,849	1,864,962
Other Expenses				(4,010,300) (6,055,342)	(1,847,336) (1,780,826)	(13,611)	(463,478)	(36,227)	(593,435)
State and Federal Income Taxes		TXINCPE		27 184 242 E	a rua ua	(ZCC,UZ)	(699,814)	(54,700) [54,700]	(896,037)
Specific Assignment of Interruptible Credit				(3 519 894)	¢ 470'en	(200,024)	¢ 611,280,8	\$ N68,126	8,264,388
Allocation of Interruptible Credits		SCP		3,519,894 \$	1,511,175 \$	2,563 \$	514,921 \$	- 41,545 \$	625,034
Adjustments to Operating Expenses:									
Eliminate mismatch in tuel cost recovery		Enerav		(2 005 300) \$	(R73 190) C	13 0451 \$	1023 620)		
Remove ECR expenses		ECRREV		(1.766.344) \$	(670,920) \$	e (c+o'e)	\$ (N20'007) \$ (1966 AB7)	(20,24/) \$	(360,2/1) (305 305)
Eliminate brokered sales expenses		Energy		(25,030,766) \$	(8.402.958) \$	(38 013) \$	(2 916 114) \$		(202,202) (300,706,6)
Eliminate DSM Expenses		DSMREV		(3,280,013) \$	(2,773,781) \$	* S	(109.057) \$		(4,437,000) (260 540)
Year end Expense adjustment		YREND		1,458,544 \$	687,488 \$	(5.575) \$	(155.950) \$		520 439
Adjustment to annualize depreciation expense		DET		8,959,741 \$	4,163,762 \$	31,876 \$	1.039.911 \$	29.601 \$	1 307 470
Leprecation adjustment		DET			43	<i>и</i> л			
Adjustment for seasing and shed of the source of the source of the season of the source of the sourc		LBT		918,580 \$	437,787 \$	3,194 \$	114,202 \$	8,491 \$	130,863
Aujustrient für perision and post Ket Exp. (See Functional Assignment) Storm damage adjustmant					i				
Adjustment to eliminate advertision expense (See Functional Assimoment)		SUALL		70,492 \$	46,793 \$	694 \$	9,491 \$	283 \$	5,995
Amortization of rate case expenses		OMT		323 EBN &	4 870 GAS	e F			
Amortization of ESM audit expenses		R01		58.333 5	27.362 S	* 3// * 1/2	02/014 4	3,790 \$	54,436
Remove one-utility cost (See Functional Assignment)					A 100'11	•	A C/+'0	¢ /00	1/0/01
Adjustment for injuries and damages (See Functional Assignment)									
Adjustment for VUI net savings to shareholders		LBT		5,640,000 \$	2,687,975 \$	19,612 \$	701,192 \$	52,132 \$	803,485
Adjustment for merger savings		LBT		19,427,401 \$	9,258,932 \$	67,554 \$	2,415,307 \$	179,573 \$	2.767,663
MISO Schedula 10 met ger amoruzauon expenses		LBT		(2,722,005) \$	(1,297,284) \$	(9,465) \$	(338,413) \$	(25,160) \$	(387,782)
Adjustment runnishive effort of accounting the				209,577 \$	293,620 \$	1,075 \$	77.972 \$	7,623 \$	121,679
Adjustment for IT staff reduction				5,280,909 \$	2,454,139 \$	18,788 \$	612,928 \$	46,917 \$	770,628
Remove Alstom Fxnenses		21 DDT		(431,834) \$	(205,808) \$	(1,502) \$	(53,688) \$	(3,992) \$	(61,520)
Adjustment for Obsolete inventory write-off				(1 27, 294U) &	\$ (128/269) \$ (020 260)	(3.269) \$	(237,093) \$	(23,181) \$	(369,994)
Adjustment for corporate office lease		LBT		1 798 420 \$	857 111 C	(4,001) \$	(155,/53) \$	(12,377) \$	(202,830)
Adjustment for carbide lime write-off		Energy		(1 416 711) \$	(A75 507) &		A 000,077	10,023	5296,209
Adjustment for Cane Run repair refund		PLPPT		3.588.000 \$	1 484 697 \$	(z, 1)2) #	204 250 E	<pre></pre>	(020,902)
VDT Amortization and Surcredit		VDTREV		(224,718) \$	(87,676) \$	(286) \$	1 224,203	20,240 4	6/2/CL0
l otal Expense Adjustments				7,834,614	6,414,712	84,946	980,157	(55,406)	546,054
Total Operating Expenses	щ		÷	641 000 200 C	767 700 010 E				
	ļ		,			¢ 0/0'070'1	01,000,/38 \$	r,160,270 \$	106, /9/,43/
Net Operating Income ~ Pro-Forma			€	67,635,652 \$	11,486,338 \$	(373,051) \$	16,424,019 \$	1,048,089 \$	16,719,374
Net Cost Rate Base			**	1,473,843.556 \$	680,151,878 \$	5,062,926 \$	170,825,435 \$	13,283,070 \$	216,869,731
Rate of Retirm									
				4.59%	1.69%	-7.37%	9.61%	1.00%	7.71%
						1			

BJP Frod Trans Allocation Removes ECR Rate Base Present Revenues reflect CSR incr CSR Credits allocated on SCP

Class Allocation 12 Months Ended September 30, 2003

Description	f Name	Allocation Vector		Rate LC-TOD Primary	Rate LC-TOD Secondary	Rate LP Primary	Rate LP Secondary	Rate LP-TOD Transmission	Rate LP-TOD Primary
Cost of Service Summary Pro-Forma									
Operating Expenses									
Oneration and Maintenance Evnences			ť	0.676.007 \$	12 270 238 \$	4 189 373 \$	21 079 136 \$	12 933 219 \$	58 234 595
Operation and Amortization Expenses			•						8.610.365
Accretion Expense				8,605	12,203	3,591	18,058	11,102	52,093
Property and Other Taxes		NPT		194,215	278,048	83,186	429,566	228,575	1,155,432
Amortization of Investment Tax Credit				(61,800)	(88,475)	(26,470)	(136,689)	(72,733)	(367,661)
Other Expenses				(93,312)	(133,591)	(39,967)	_	(109,821)	(555, 137)
State and Federal Income Taxes		TXINCPF	\$	745,236 \$	1,070,672 \$	286,102 \$	2,498,379 \$	686,335 \$	2,276,389
Specific Assignment of Interruptible Credit			,					(1,637,062)	(1,396,833)
Allocation of Interruptible Credits		SCP	ю	66,076 \$	84,505 \$	29,945 \$	140,138 \$	60,511 \$	50'07Z
Adjustments to Operating Expenses:									
Eliminate mismatch in fuel cost recovery		Energy	t)	(44,786) \$	(54,061) \$	(19,122) \$	(96,898) \$	(63,230) \$	(273,643)
Remove ECR expenses		ECREV	\$	(32,690) \$	(43,382) \$	(14,011) \$	_		(177,854)
Eliminate brokered sales expenses		Energy	÷	(559,033) \$	(674,807) \$	(238,687) \$	(1,209,515) \$	(789,257) \$	(3,415,692)
Eliminate DSM Expenses		DSMREV	÷	(14,699) \$	(16,293) \$	۰» ۱	ده	ур ,	
Year end Expense adjustment		YREND	÷	ب	315,814 \$	دی ۱	82,513 \$		
Adjustment to annualize depreciation expense		DET	63	135,576 \$	194,294 \$	58,229 \$	301,511 \$	157,916 \$	805,053
Depreciation adjustment		DET	6 9 (۰.	• • • • •		· · ·	69 6 - 1 - 1	, 010.00
Labor adjustment	4	197	÷	\$ 105'51	4 CUE 81	C. 202 3	\$ BUD,15		03' 7 40
Aglusument for pension and post rest exp. (See Functional Assignment) Storm domage adjustment	menu	CDAL	¥	454 4	710 5	3 100	1 509 \$		7 235
atom uamage aujusumenk Adjustment to eliminate advertising expense (See Functional Assignment)	onment)	aDALL	9	5 7 7	۵ 	A 177	* pop'-	•	P0414
Amortization of rate case expenses		OMT	v	6.353 \$	8.055 \$	2.750 \$		8.490 \$	38,229
Amortization of ESM audit expenses		R01	- 103	1,081 \$	1,418 \$	461 \$	2,604 \$	1,162 \$	5,739
Remove one-utility cost (See Functional Assignment)									
Adjustment for injuries and damages (See Functional Assignment)	_								
Adjustment for VDT net savings to shareholders		LBT	63 -	85,697 \$	116,073 \$	38,487 \$	190,388 \$	105,554 \$	511,087
Adjustment for merger savings			69 1	295,190 \$	399,821 \$	132,571 \$	655,80/ \$	353,588 \$	1,/60,4/9
Adjustment for merger amortization expenses			49 6	(41,36U) \$	\$ (020'9C)	<pre>\$ (16,6,0)</pre> \$ (16,6,0)	(409,19)	4 (546)00) 4 000 00	(240,004) 70,010
MISU Schedule 10 one time creat		ארוא סבי	A 6	70,000 €	10,121 5		2/, 204 4	e 700'11	174 503
Adjustment cumulative effect of accounting change		UCI LET	A .	(a) 202 a)	(14) (14) (14) (14) (14) (14) (14) (14)		111,112 S	0 //0'02 0 //0'02	200,414
Aujustinani 1911 stali reucion Demons African Evisiones			9 W	a (200'a)	(cooci) +	(16 753) \$	(14,247) S	(1207) (51791) \$	(26,125)
Adinote Assum Expenses Adinotement for Obsolute investions write-off			÷.	(21 108) 5	\$ (572'OF)	(9 045) \$			(125.542)
Adjustment for comorate office lease		E I) es	27 326 \$	37.012 \$	12.272 \$	60.709	33,658 \$	162.970
Adjustment for carbide lime write-off		Energy	- 13	(31,641) \$	(38,193) \$	(13.509) \$	(68,457) \$	(44,671) \$	(193,324)
Adjustment for Cane Run repair refund		PLPPT	- 64	66,753 \$	94.662 \$	27,859 \$	140,088 \$	86,124 \$	404,112
VDT Amortization and Surcredit		VDTREV	- 47	(4,116) \$	(5,407) \$	(1,762) \$	(9.874) \$	(4,381) \$	(21,640)
Total Expense Adjustments				(10,639)	335,809	(15,461)	(16.253)	(188,560)	(408,937)
Total Operating Expenses	TOE		69	11,915,416 \$	15,907,456 \$	5,133.082 \$	27,030,724 \$	13,600,546 \$	67,870,340
Net Operating Income – Pro-Forma			69	1,558,549 \$	2,237,236 \$	615,194 \$	4,792,099 \$	1,532,501 \$	5,859,251
Net Cost Rate Base			÷	22,620,354 \$	32,257,851 \$	9,710,208 \$	50,173,059 \$	26,606,267 \$	134,517,544
Rate of Retrict				6.89%	6.94%	6.34%	7.53.6	5.76%	4.36%

BIP Prod Trans Allocation Removes ECR Rate Base Present Revenues reflect CSR incr CSR Credits allocated on SCP

Exhibit (SJB-7) Page 5 of 6

Class Allocation 12 Months Ended September 30, 2003

Description	f Name	Allocation Vector		Rate LP-TOD Secondary	Street Lighting Rate PSL	Street Lighting Rate SLE	Street Lighting Rate OL	Street Lighting Rate TLE	Special Contracts
Cost of Service Summary – Pro-Forma									
Operating Expenses									
			ю	1,680,600 \$	2,990,230 \$	160,034 \$	3,323,607 \$	437,073 \$	27,073,406
bepreview and Alitoriuzation Expenses Arreation Expanse				277,050	1,363,409	29,200	1,730,013	64,211	3,857,568
				1,484	2,013	160	2,088	355	23,571
A montantian of low actions of the state and the state		TPT		36,758	169,343	3,883	213,859	8,544	518,157
Anoundanun Uninvesurierin Fax Credit Other Evnenses				(11,696)	(53,885)	(1,235)	(68,050)	(2,719)	(164,879)
State and Federal Income Taves		TVN/DE	•	(100'/1)	(81,362)	(1,865)	(102,751)	(4,105)	(248,953)
Specific Assignment of Internutible Credit			9	¢ 170'801	\$ 660'ZNZ	\$ (204'5)	319,845 \$	29,836 \$	1,712,774
Allocation of Interruptible Credits		SCP	ŝ	12,085 \$	63	••	и л 1 (- 1,678 \$	(486,000) 159,682
Adjustments to Operating Expenses:									
Eliminate mismatch in fuel cost recovery		Energy	5	(7,490) \$	(8.992) \$	(698) \$	\$ (498.6)	\$ U20 67	(128 257)
Remove ECR expenses		ECRREV			(15.470) \$	(127) S	(19.117) \$		(100'071)
Eliminate brokered sales expenses		Energy	675	(93,494) \$	(112.246) \$	(8.719) \$	(116.606) \$	(25.054) \$	(1 602 451) (1 602 194)
Eliminate DSM Expenses		DSMREV	69			**	5		(
Year end Expense adjustment		YREND	ы		1,673 \$	(647) \$	9.548 \$	3.240 \$	I
Adjustment to annualize depreciation expense		DET	69	25,904 \$	127,476 \$	2,730 \$	161,753 \$	6,004 \$	360.676
Depreciation adjustment		DET	so	• ?	s	s ,	57 1	. 1	
	;	LBT	÷	2,585 \$	5,797 \$	267 \$	6,433 \$	675 \$	37,717
Aujustment for pension and post Ret Exp. (See Functional Assignment) Storm demost editional	nent)								
ourn uamage aujusment Adjustment to aliminate advartision evoanse /See Functional Assimument)	()	SDALL	•	164 \$	487 \$	15 \$	508 \$	27 \$	896
Amortization of rate case expenses	листи)	OMT	e	a 011	• 660	e 107			i
Amortization of ESM audit expenses		ROI	• •	500 S	* 90F	5 ¥	2, 102 y	4 /07	5/1/,11
Remove one-utility cost (See Functional Assignment)			•		•	2			100'7
Adjustment for injuries and damages (See Functional Assignment)									
Adjustment for VDT net savings to shareholders		LBT	€	15,871 \$	35,591 \$	1,639 \$	39,498 \$	4,142 \$	231.578
Adjustment for merger savings		LBT	÷	54,668 \$	122,595 \$	5,646 \$	136,052 \$	14,268 \$	797,688
Adjustment for merger amortization expenses		LBT	•>	_	(17,177) \$	(181) \$	(19,062) \$	(1,999) \$	(111,765)
Misculoschedule 10 one time credit		PLTRT	649 (2,277 \$	3,089 \$	246 \$	3,204 \$	545 \$	36,161
Adjustment for IT staff reduction Adjustment for IT staff reduction					75,135 \$	1,609 \$	95,338 \$	3,539 \$	212,584
Aguarman tor it statt reduced Remove Aletom Eveneses		ים מיום		(1,215) 5		(125) \$	(3,024) \$	(317) \$	(17,731)
Adjustment for Obside investory write-off			₽ 6		\$ (L6C'A)	(/48) \$	(9.742) S	(1.656) \$	(109,957)
Adjustment for connorate office lease			₽ 6		(18,620) \$	(422) \$	(23,538) \$	(630) \$	(56,291)
Adjustment for carbida lime write. of		Foomu	96			e (70	\$ 1000 U	4 170°L	13,843
Adjustment for Cane Bun report refund		Chergy Di DOT	6 6	(287'C)	(505,0) 2 (505,0)	(493) 5	(6,600) \$	(1,418) \$	(30,682)
VDT Amortization and Surcredit			θ ₩	4 710'11	4 /10/01	1,244 \$	16,200 \$	2,754 \$	182,851
Total Expense Adjustments		7 C C C C	•	e (051)	200 456	¢ (70)	5 (067 J	(206) \$	(10,853)
				704'1	200,400	190	274,601	1,524	(258,718)
Total Operating Expenses	TOE		ŝ	2,139,702 \$	4,801,103 \$	187,590 \$	5,693,263 \$	566,398 \$	32,186,608
Net Operating Income – Pro-Forma			ŝ	324,363 \$	651,910 \$	2,124 \$	923,997 \$	111,362 \$	3,722,296
Net Cost Rate Base			\$	4,292,210 \$	20,157,813 \$	451,450 \$	25,495,128 \$	1,001,089 \$	60,367,542
Bath of Date-									1
				7.56%	3.23%	%2*0	3.62%	11.12%	6.17%

BIP Prod Trans Allocation Removes ECR Rate Base Present Revenues reflect CSR incr CSR Credits allocated on SCP

Exhibit _____ (SJB-7) Page 6 of 6

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

IN THE MATTER OF:

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

EXHIBIT (SJB-8)

LOUISVILLE GAS AND ELECTRIC COMPANY	Cost of Service Study	Class à llasation
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Class Allocation 12 Months Ended September 30, 2003

Description	Ref Name	Allocation Vector		System	Residential Rate R	Water Heating Rate WH	General Service Rate GS	Rate LC Primary	Rate LC Secondary
Cost of Service Summary – Pro-Forma						:			
Operating Revenues									
⊺otal Operating Revenue – Actual			ŝ	768,525,785 \$	291,603,270 \$	1,158,990 \$	107,524,685 \$	8,982,068 \$	132,709,052
Pro-Forma Adjustments:									
Eliminate unbilted revenue		R01	\$	(1,867,000) \$	(715.724) \$	(2 428) \$	(271.251) \$	21 33G) \$	(152 225)
Mismatch in fuel cost recovery		Energy		(4,406,145)	(1,479,166)	(6,691)		(58.331)	(791 604)
I o Kettect a Full Year of the FAC Roll-In	FACRI			547,241	181,639	1,202	87,109	11.617	139.923
	ECRREV			(11,228,429)	(4,264,952)	(15,362)	(1,630,456)	(127,642)	(1.940.152)
IO REPORT & FUIL YEAR OF THE ECK ROILIN	ECRRI			723,260	255,297	937	110,897	9,089	133,401
Kemove off-system ECR revenues		РГРРТ		(1,929,923)	(792,562)	(7,045)	(258,546)	(22,434)	(320,785)
Climinate Drokered sales		Energy		(22,608,445)	(7,589,772)	(34,335)	(2,633,910)	(299.304)	(4 061 814)
Climinate ESM revenues	ESMREV			(6,974,780)	(2,763,963)	(7,154)	(1,009,115)	(80,480)	(1.196.285)
Eliminate Rate Retund Acct		R01		(7,150,231)	(2,741,076)	(9,299)	(1,038,835)	(81,725)	(1,234,463)
	DSMREV			(3.277,501)	(2,771,657)	•	(108,973)	(25.623)	(340,279)
Y ear End Revenue Adjustment	YREND			2,614,347	1,232,278	(8,993)	(279,531)	1	932 854
Adjustment for Merger savings		R01		(2,758,795)	(1,057,598)	(3,588)	(400,817)	(31,532)	(476 296)
Adjustment for Clustomer Rate Switching & CSR Credit	RATESW			(621,927)		•	. •	1	-
VUL Amortization and Surcredit		VDTREV		44,485	17,356	57	6,447	505	7,617
Total Pro-Forma Operating Revenue			49	709.631.942 \$	269 113 371 🙎	1 065 280 \$	00 584 387 &	0 020 N2C 0	

Carry all and a

Class Allocation 12 Months Ended September 30, 2003

Description	Ref	Name	Allocation Vector		Rate LC-TOD Primary	Rate LC-TOD Secondary	Rate LP Primary	Rate LP Secondary	Rate LP-TOD Transmission	Rate LP-TOD Primary
Cost of Service Summary - Pro-Forma										
Operating Revenues										
Total Operating Revenue – Actual				ŝ	14,666,854 \$	18,848,201 \$	6,311,999 \$	34,454,413 \$	16,765,931 \$	79,766,951
Pro-Forma Adjustments:										
Eliminate unbilled revenue			R01	ŝ	(34,589) \$	(45,400) \$	(14,766) \$	(83,348) \$	(37,178) \$	(183,683)
Mismatch in fuel cost recovery			Energy		(98,406)	(118,786)	(42,016)	(212,910)	(138,932)	(601,261)
To Reflect a Full Year of the FAC Roll-In		FACRI			16,117	24,738	5,030	28,206	10,866	20,692
Remove ECR revenues		ECRREV			(207,809)	(275,776)	(89,065)	(505, 167)	(223,730)	(1,130,594)
To Reflect a Full Year of the ECR RolHn		ECRRI			14,884	21,249	5,484	35,195	16,754	67,122
Remove off-system ECR revenues			РЦРРТ		(36,425)	(43,661)	(17,332)	(79,984)	(42,430)	(183,484)
Eliminate brokered sales			Energy		(504,933)	(609,504)	(215,588)	(1,092,466)	(712,877)	(3,085,143)
Eliminate ESM revenues	-	ESMREV			(130,047)	(164,826)	(53,219)	(301,827)	(135,771)	(845,195)
Eliminate Rate Refund Acct			R01		(132,469)	(173,873)	(56,551)	(319,207)	(142,383)	(703,468)
Eliminate DSM Revenue	-	DSMREV			(14,688)	(16,281)	•	. '	,	
Year End Revenue Adjustment		YREND			•	566,077		147,900	•	•
Adjustment for Merger savings			R01		(51,111)	(67,086)	(21,819)	(123,161)	(54,936)	(271,421)
Adjustment for Customer Rate Switching & CSR Credit	-	RATESW			ſ	,	,	1	(279,699)	(252,228)
VDT Amortization and Surcredit			VDTREV		815	1,070	349	1,955	867	4,284
Total Pro-Forma Operating Revenue				ы	13,488,192 \$	17,946,145 \$	5,812,504 \$	31,949,599 \$	15,026,482 \$	72,802,571

LOUISVILLE GAS AND ELECTRIC COMPANY	Cost of Service Study	
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			Allocation		Rate LP-TOD	Street Lighting	Street Lighting	Street Lighting	Street Lighting	Special
Description	Ref	Name	Vector		Secondary	Rate PSL	Rate SLE	Rate OL	Rate TLE	Contracts
Cost of Service Summary – Pro-Forma										
Operating Revenues										
Total Operating Revenue – Actual				\$	2,756,699 \$	5,846,370 \$	211,367 \$	7,056,532 \$	715,799 \$	39,146,605
Pro-Forma Adjustments:										
Eliminate unbilled revenue			R01	÷	(6,454) \$	(15,890) \$	(464) \$	(19,577) \$	(1,786) \$	(90,792)
Mismatch in fuel cost recovery			Energy		(16,458)	(19,759)	(1,535)	(20,526)	(4,410)	(282,033)
To Reflect a Full Year of the FAC Roll-In		FACR	;		1,436	(3,891)	156	(1,432)	162	23,036
Remove ECR revenues		ECRREV			(40,296)	(98,342)	(3,010)	(121,526)	(11,097)	(543,453)
To Reflect a Fut! Year of the ECR Roll-In		ECRRI			3,088	6,611	212	9,072	811	33,157
Remove off-system ECR revenues			РГРРТ		(9,329)	(8,899)	(062)	(9,385)	(1,069)	(95,761)
Eliminate brokered sales			Energy		(B4 446)	(101,383)	(7,875)	(105,321)	(22,630)	(1,447,143)
Eliminate ESM revenues		ESMREV			(20,232)	(57,193)	(1,416)	(65,875)	(6,308)	(335,874)
Eliminate Rate Refund Acct			R01		(24,719)	(60,854)	(1,778)	(74,974)	(6,841)	(347,716)
Eliminate DSM Revenue		DSMREV			•	1	1	•	•	. 1
Year End Revenue Adjustment		YREND				2,999	(1,159)	17,114	5,808	•
Adjustment for Merger savings			R01		(9,537)	(23,479)	(686)	(28,928)	(2,639)	(134,160)
Adjustment for Customer Rate Switching & CSR Credit		RATESW			•	•	ı			(000'06)
VDT Amortization and Surcedit			VDTREV		146	364	10	453	41	2,148
Totat Pro-Forma Operating Revenue				ŧ\$	2,549,898 \$	5,466,655 \$	193,033 \$	6,635,628 \$	666,475 \$	35,838,013

LOUISVILLE GAS AND ELECTRIC COMPANY	Cost of Service Study	Class Allocation
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Description	Ref Name	Allocation Vector		Total System	Residential Rate R	Water He∎ting Rate WH	General Service Rate GS	Rate LC Primary	Rate LC Secondary
Cost of Service Summary – Pro-Forma								-	
Operating Expenses									
Oneration and Maintenance Exnences			4						
Depreciation and Amortization Expenses			÷	95, 827, 965	204,145,504 \$	1,503,840 \$	63,463,421 \$	5,864,100 \$	81,976,232
Accretion Expense				462.519	189 943	1688	12,010,178 61 Q67	5 176 5 176	75 878
Property and Other Taxes		NPT		12.603.252	5.775.892	63.041	1 685 080	122 202	1 815 007
Amortization of Investment Tax Credit				(4,010,380)	(1,837,901)	(20,060)	(536, 196)	(38,887)	(577,539)
Other Expenses				(6,055,342)	(2,775,078)	(30,288)	(809,611)	(58,715)	(872,036)
State and Federal income Taxes		TXINCPF		27,184,243 \$	62,557 \$	(466,405) \$	6,799,629 \$	465,558	8,756,882
Specific Assignment of Interruptible Credit				(3,519,894)		•	1		
Allocation of Interruptible Credits		SCP1		3,519,894 \$	1,511,175 \$	2,563 \$	514,921 \$	41,545 \$	625,034
Adjustments to Operating Expenses:									
Eliminate mismatch in fuel cost recovery		Energy		(2.005.300) \$	(673.190) \$	(3.045) \$	(233.620) \$	(26.547) \$	(360 274)
Remove ECR expenses		ECREV		(1,766,344) \$	(670,920) \$	(2.417) \$	(256.487) \$	(20 0Z)	(305 205)
Eliminate brokered sales expenses		Energy		(25,030,766) \$	(8,402,958) \$	(38,013) \$	(2.916.114) \$	(331.372) \$	(4,497,006)
Eliminate DSM Expenses		DSMREV		(3,280,013) \$	(2,773,781) \$	· ·	(109,057) \$	(25,643) \$	(340,540)
Year end Expense adjustment		YREND		1,458,544 \$	687,488 \$	(5,575) \$	(155,950) \$		520,439
Adjustment to annualize depreciation expense		DET		8,959,741 \$	4,143,283 \$	45,871 \$	1,197,729 \$	85,373 \$	1,272,971
Leprecation adjustment		DET		• •	, ,	• •	н э	۶۹ י	,
Adjustment for proving and need Det Fire (See Fired) and	4	LBT		918,580 \$	436,409 \$	4,136 \$	124,822 \$	8,879 \$	128,541
Aujusunteni jui pelision aria post Ket Exp. (See Functional Assignment) Storm domage adjustmost	(Juamr								
ocom uamage adjustment. Adjustment to aliminate advertising expanse (See Functional Assignment)	(incment)	SUALL		/0,492 \$	46,/93 \$	694 \$	9,491 \$	283 \$	5,995
Amortization of rate case expenses	agranter m	OMT		223 CBO &	134 043 E	. 100			
Amortization of ESM audit expenses		ROI		58.333 \$	20,367 5	301 &	41,001 40 8.475 45	3,03U &	13,614
Remove one-utility cost (See Functional Assignment)						2		* m	
Adjustment for injuries and damages (See Functional Assignment)	¢								
Adjustment for VDT net savings to shareholders		LBT		5,640,000 \$	2,679,514 \$	25,394 \$	766,396 \$	54,517 \$	789,231
Adjustment for merger savings		LBT		19,427,401 \$	9,229,788 \$	87,471 \$	2,639,907 \$	187,788 \$	2,718,566
Adjustment for merger amortization expenses		LBT		(2,722,005) \$	(1,293,201) \$	(12,256) \$	(369,882) \$	(26,311) \$	(380,903)
		PLTRI		209,577 \$	291,402 \$	2,590 \$	95,060 \$	8,248 \$	117,944
Adjustment for iT staff reduction accounting change		UE I		5,280,909 \$	2,442,069 \$	27,036 \$	705,946 \$	50,319 \$	750,295
Remove Alstom Exhenses				(401,004) a (3157,640) é	\$ (101'077) \$ (000'020)	(1,844) &		(4,1/4) 5	(60,429)
Adjustment for Obsolate inventory write-off		L L L			(E30,542) \$	e (//o//)	\$ (703'CO)	(190,02)	(358,536)
Adjustment for corporate office lease		LBT			854 414 \$	R 097 S		* (co7/ci)	(197,41U) 251,664
Adjustment for carbide lime write-off		Energy		(1,416,711) \$	(475,597) \$	(2.152) \$		(18,755) \$	(254 525)
Adjustment for Cane Run repair refund		PLPPT		3,588,000 \$	1,473,485 \$	13,099 \$	480,674 \$	41,708 \$	596.385
VDT Amortization and Surcredit		VDTREV		(224.718) \$	(87,676) \$	(286) \$	(32,570) \$	(2.549) \$	(38,480)
l otal Expense Adjustments				7,834,614	6,341,917	135,026	1,544,530	(34,780)	422,510
Total Operating Expenses	TOE		ø	641,996,290 \$	257,728,118 \$	1,680,010 \$	85,533,915 \$	7,279,507 \$	105,837,897
Net Operating Income – Pro-Forma			67	67,635,652 \$	11,385,253 \$	(614,721) \$	14,050.468 \$	975,361 \$	17,400,941
			4						
Net Cost Kate Base			÷	1,473,643,556 \$	676,820,462 \$	7,339,572 \$	196,498,956 \$	14,222,061 \$	211.257,595
Rate of Return				4.59%	1.68%	-8.38%	7.15%	1.00%	8.24%

Average and Excess Prod Trans Allocation All Other KIUC Corrections Included

Exhibit (SJB-8) Page 4 of 6

LOUISVILLE GAS AND ELECTRIC COMPANY	Cost of Service Study	Class Allocation
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Description	Ref h	Name	Allocation Vector		Rate LC-TOD Primary	Rate LC-TOD Secondary	Rate LP Primary	Rate LP Secondary	Rate LP-TOD Transmission	Rate LP-TOD Primary
Cost of Service Summary Pro-Forma										
Operating Expenses										
Onortica and Mainteenergy										
Derectation and Amodificer Expenses				÷	9,672,397 \$	11,728,441 \$	4,342,362 \$	21,322,155 \$	12,620,140 \$	55,734,309
Appreciation Environmentation Expenses					1,468,922	1,814,501	708,038	3,393,056	1,547,527	7,379,861
					8,729	10,464	4,154	19,169	10,169	43.973
Anopeny and Other Laxes			NPT		196,772	242,367	94,729	452,349	209,424	988,835
					(62,613)	(77,122)	(30,143)	(143,938)	(66,639)	(314,649)
					(94,541)	(116,447)	(45,513)	(217, 335)	(100.619)	(475.095)
Create and regeral income laxes			TXINCPF	ъ	740,596 \$	1,370,270 \$	197,818 \$	2,346,968 \$	855,773 \$	3.663.837
opediic Assignment of Interruptole Credit Allocation of Interruption Condition					•			•	(1.637,062)	(1,396,833)
			SCP1	ы	66,076 \$	84,505 \$	29,945 \$	140,138 \$	60.511 \$	270,035
Adjustments to Operating Expenses:										
Eliminate mismatch in fuel cost recovery			Enerav	~	(44 786) \$	(54 DE1) \$	9 (CE 10)	/DC 000/ 6	e (000 Lo/	
Remove ECR expenses			ECRREV	1 41	(32,690) \$	(43.382) \$		(30,030) a	(03,23U) &	(2/3/643)
Eliminate brokered sales expenses			Energy	69	(559.033) \$	(674 807) S			(20,190) 5	(11, 1504) (0
Eliminate DSM Expenses			DSMREV	. 63	(14.699) \$	(16.293) \$			* (/C7'E0/)	(780'c1+'c)
Year and Expense adjustment			YREND	ы		315,814 \$	1	82 513 \$		•
Adjustment to annualize depreciation expense			DET	\$	137,342 \$	169,653 \$	66.200 \$	317.245 \$	144 691 \$	590 004
Depreciation adjustment			DET	\$	۶۹ ,	\$	• • •	69		-
Labor adjustment			LBT	••	14,076 \$	17,246 \$	6,805 \$	32,067 \$	16.301 \$	75.498
Adjustment for pension and post Ret Exp. (See Functional Assignment) Storm demona adjustment	Inment)			•					-	
own: uamaya aujusunem. Adjustment to eliminate advertising expenses /See Eurodiscont Aminement	(and mentioned)		SUALL	6	454 \$	719 \$	221 \$	1,509 \$	++>	2,235
Amontration of rate case expenses	namneut		110	e						
Amortization of ESM audit expenses				÷ ₩	5,350 \$	7,699 5	2.851 \$	13,997 \$	8,285 \$	36,587
Remove one-utility cost (See Functional Assignment)				9	¢ 100'1	4 10 4	467 \$	2,604 \$	1,162 \$	5,739
Adjustment for injuries and damages (See Functional Assignment)	£									
Adjustment for VDT net savings to shareholders			LBT	69	86.427 \$	105.892 \$	41 7B0 \$	196 880 ¢		163 EEA
Adjustment for merger savings			LBT	6	297,703 \$	364.752 \$	143.915 \$	678 199 \$	344 766	1 506 7AE
Adjustment for merger amortization expenses			LBT	s	(41.712) \$	(51,106) \$	(20.164) \$	(85.024) \$	(48.306) \$	(223,723)
MISO Schedule 10 one time credit			PLTRT	÷	13,392 \$	16,053 \$	6.373 \$	29,408 \$	15.600 \$	67,462
Adjustment cumulative effect of accounting change			DET	69	80,950 \$	99,994 \$	39,019 \$	186,985 \$	85,281 \$	406.691
Bemain of the Evance Concert				69 1	(6,617) \$	(8,108) \$	(3,199) \$	(15,075) \$	(7,663) \$	(35,493)
itemate Astorii Experises Adiustment for Obsolate inventory action at				69 ((40,723) \$	(48,812) \$	(19,377) \$	(89,422) \$	(47,436) \$	(205, 134)
Adjustment for commate office lease				~ ·	(21,386) \$	(26,353) \$	(10,297) \$	(49,199) \$	(22,725) \$	(107,465)
Adjustment for carbide lime write-off			Eneraid	л ь		33,/66 5	13,322 \$	62,782 \$	31,915 \$	147,813
Adjustment for Cane Run repair refund			Linery Pi PPT	• •	(31,041) &	(30,193) \$	(13,509) 5	(58,457) \$	(44,671) \$	(193,324)
VDT Amortization and Surcredit			VDTREV	• •	(4116) 5	(5,407) \$	32,223 3	148,/02 3	(8,883 5	341,123
Total Expense Adjustments					(84.351)		13 043	30.050	(195 800)	121.540)
						100,113	740'01	2015/60	(069'067)	(820,517)
Total Operating Expenses	F	106		63	11,931,987 \$	15,304,633 \$	5,314,432 \$	27,352,530 \$	13,263,334 \$	65,073,757
Net Operating Income ~ Pro-Forma				69	1,556,204 \$	2,641,512 \$	498,073 \$	4,597,069 \$	1.763.148 \$	7 728 814
Net Cost Bate Bare									•	
				v	22,907,580 \$	28,249,267 \$	\$1,006,955 \$	52,732,604 \$	24,454,785 \$	115,801,430
Rate of Return					6.79%	7326	7823 8	0 744/	7 4401	
							0/ AA11	A14 214	a. 17.1	0.01%

Average and Excess Prod Trans Allocation All Other KIUC Corrections Included

Exhibit _____(SJB-8) Page 5 of 6

Class Allocation 12 Months Ended

12 Months Ended September 30, 2003

Cost of Service Summary – Pro-Forma Operating Expenses Depretation and Maintenance Expenses Deprectation and Annortization Expenses Accretion Expenses Property and Cherr Tax Credit Annortization of Investment Tax Credit Annortized on Investment Tax Credit State and Federal Income Taxes State and Federal Incom	a a a a a	1.914.697 \$					
ses enses adi Credit Saf recovery		1.914.697 \$					
ses enses adri Credit das recovery denses		1.914.697 \$					
erses entress Credit dat recovery denses		314.697 S					
adit Credit ast recovery Denses	<i></i>		3,075,140 \$	173,208 \$	3,423,529 \$	405,680 \$	26,784,204
adit Credit ast recovery penses	u v v u	706'069	1,361,515	33,605	1,754,394	49,231	3,763,469
sdit Credit ast recovery Jenses	es es es es	51 1 22	2, 133 174 704	891 921	2,249	256	22,950
Credit ssf recovery denses	ی وی دی دی ا	32, 103 (16 605)	171,134 /54.665	4,4,9	217,160	6,515	505,418
Credit ast recovery penses		(25,072)	(04'300) (80 540)	(074'))		(2,0/3)	(160,825)
Credit ast recovery penses	ം ക ക	30.150 \$	163 835 \$	(761'7)	(104,330) 272 000 0	(3,130)	(242,832)
ast recovery Denses	40 VS V	• • • • •	•				1,000,005
ast recovery Denses	63 64	12,085 \$,	••• •	ود ، ،	1.678 \$	(486,000) 159.682
ast recovery Denses	65 6						
		(7.400) 6	(8 003) \$	/COB/ #			
		5 (02-1) (8 330) \$	(15,470) \$	(030) 4	(A'347) &	(5,007) \$	(128,357)
) w	(93.494) \$	(112 246) \$	(4/4) 4	(19,117) \$	(1,/46) \$	(85,491) /4 600 404)
	5				_		(1'anz' 134)
-	\$		1,673 \$	(647) \$	9.548 \$	3 240 5	
depreciation expense	ŝ	36,556 \$	129,169 \$	3,142 \$	164,033 \$	4,603 \$	351.878
stnemt	\$	s	ч ,		• • 3		,
Lator adjustment Adjustment for nearcian and east Dat Even 2000 Fundational Actionation	\$	3,302 \$	5,911 \$	295 \$	6.586 \$	580 \$	37,125
Automic in personalian post recipit) (See Functional Assignment)							
Summar aguage aguamen. Adiustment to eliminate advertision excense /Sea Functional Assimmant)		164 \$	487 \$	15 \$	508 \$	27 \$	396
Amortization of rate case expenses	÷	4 767 e	e 010 c				
	ο υ	a (07)	♣ BLD'7	114 5	2,247 \$	266 \$	17,583
	•						2,837
ional Assignment)							
Adjustment for VDT net savings to shareholders	59	20,272 \$	36,290 \$	1,809 \$	40.439 \$	3 564 5	227 943
	ŝ	69,828 \$	125,004 \$	6,232 \$	139.296 \$		785 167
Aujusmient for merger amortization expenses	69	(9,784) \$		(873) \$	(19,517) \$	(1,720) \$	(110,011)
	63 -	3,430 \$		291 \$	3,451 \$	393 \$	35,209
Adjustment during we eried of addung grange Adjustment for IT staff reduction	u≫ 1	21,546 \$		1,852 \$	96,682 \$	2,713 \$	207,398
	<i>n</i> .	(295,1) 2 (297,1)		(139) \$	(3,096) \$	(273) \$	(17,453)
ventory write-off	••	(10,43U) S	(9,949) 5	(884) 5	(10,492) \$	(1,195) \$	(107,061)
	•			(48/) \$	(23,896) \$	(710) \$	(54,909)
		0,404 9 (5,202) 6	11,312 \$	5//G	12,895 \$	1,136 \$	72,684
Dd) v?	17344 5	16.544 S	(490) \$	(0)0/0 (0)	(1,416) \$	(90,682)
Ind Surcredit	о <i>с</i> о	(738) \$	(1836) \$	5 (53) 5 (53)	* 100C C)	1,96/ \$	1/8,034
Total Expense Adjustments	·	39,572	214,544	2,344	282,789	(3,487)	(290.257)
Total Operating Expenses	U.	2 ANN 229 \$	4 B74 767 &	200 101 ¢	e fog att g		
	•		*	¢ 181'007	A 400'A//'C	531,768 \$	31,912,662
Net Operating Income Pro-Forma	49	149,669 \$	594,897 \$	(7.159) \$	856,064 \$	134,707 \$	3,925,351
Net Cost Rate Base	ы	6,025,129 \$	20,433,213 \$	518.452 \$	25.865.966 \$	\$ 676 522	58 036 288
							nov'ooo'oo
		2.48%	2.91%	-1.38%	3.31%	17.42%	6.66%

Average and Excess Prod Trans Allocation All Other KJUC Corrections Included

Exhibit (SJB-8) Page 6 of 6

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

IN THE MATTER OF:

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

EXHIBIT (SJB-9)

LOUISVILLE GAS AND ELECTRIC COMPANY	Cost of Service Study	Class Allacation
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Description	Ref	Nàrre	Allocation Vector		Total System	Residential Rate R	Water Heating Rate WH	General Service Rate GS	Rate LC Primary	Rate LC Secondary
Cost of Service Summary – Pro-Forma										
Operating Revenues										
Total Operating Revenue – Actual				u?	768,525,785 \$	293,491,954 \$	1,027,476 \$	106,759,166 \$	8,907,770	132,960,127
Pro-Forma Adjustments:										
Eliminate unbilted revenue			R01	69	(1,867,000) \$	(715,724) \$	(2,428) \$	(271,251) \$	(21,339) \$	(322,331)
Mismatch in fuel cost recovery			Energy		(4,406,145)	(1,479,166)	(6.691)	(513, 321)	(58,331)	(791,604)
To Reflect a Full Year of the FAC RolHin		FACRI			547,241	181,639	1,202	87,109	11,617	139,923
Remove ECR revenues		ECRREV			(11,228,429)	(4,264,952)	(15,362)	(1,630,456)	(127,642)	(1,940,152)
To Reflect a Full Year of the ECR Roll-In		ECRRI			723,260	255,297	637	110,897	9,089	133,401
Remove off-system ECR revenues			PLPPT		(1,929,923)	(859,156)	(2,408)	(231,554)	(19,814)	(329,638)
Eliminate brokered sales			Energy		(22,608,445)	(7,589,772)	(34,335)	(2,633,910)	(289,304)	(4,061,814)
Eliminate ESM revenues		ESMREV			(6,974,780)	(2,763,963)	(7.154)	(1,009,115)	(80,480)	(1,196,285)
Eliminate Rate Refund Acct			R01		(7,150,231)	(2,741,076)	(8,299)	(1,038,835)	(81,725)	(1,234,463)
Eliminate DSM Revenue		DSMREV			(3,277,501)	(2,771,657)		(108,973)	(25,623)	(340,279)
Year End Revenue Adjustment		YREND			2,614,347	1,232,278	(8,993)	(279,531)	•	932,854
Adjustment for Merger savings			R01		(2,758,795)	(1,057,598)	(3,588)	(400,817)	(31,532)	(476,296)
Adjustment for Customer Rate Switching & CSR Credit		RATESW			(621,927)	4	1	•	•	
VDT Amortization and Surcredit			VDTREV		44,485	17,356	57	6,447	505	7,617
Total Pro-Forma Operating Revenue				ŵ	709,631,942 \$	270,935,461 \$	938,413 \$	98,845.856 \$	8,183,190 \$	123,481,059

Cost of Service Study	Class Allocation
	Cost of Service Study

Description	Ref Name	Allocation Vector		Rate LC-TOD Primary	Rate LC-TOD Secondary	Rate LP Primary	Rate LP Secondary	Rate LP-TOD Transmission	Rate LP-TOD Primary
Cost of Service Summary – Pro-Forma									
Operating Revenues									
Total Operating Revenue – Actual			ø	14,586,905 \$	18,999,493 \$	6,226,733 \$	34,167,324 \$	16,612,432 \$	79,626,726
Pro-Forma Adjustments:									
Eliminate unbilled revenue		R01	63	(34,589) \$	(45,400) \$	(14.766) \$	(83.348) \$	(37,178) \$	(183 683)
Mismatch in fuel cost recovery		Energy		(98,406)	(118,786)	(42,016)	(212,910)		(601.261)
To Reflect a Full Year of the FAC Roll-In	FACRI			16,117	24,738	5,030	28,206	10.866	20.692
Remove ECR revenues	ECRRE	>		(207,809)	(275,776)	(89,065)	(505,167)	(223,730)	(1.130.594)
To Reflect a Full Year of the ECR Roll-In	ECRRI			14,884	21,249	5,484	35,195	16.754	67 122
Remove off-system ECR revenues		PLPPT		(33,606)	(48,995)	(14,326)	(69,862)	(37.018)	(178.540)
Eliminate brokered sales		Energy		(504,933)	(609,504)	(215,588)	(1,092,466)	(712,877)	(3.085.143)
Eliminate ESM revenues	ESMREV			(130,047)	(164,826)	(53,219)	(301,827)	(135,771)	(645, 195)
Eliminate Rate Refund Acct		R01		(132,469)	(173,873)	(56,551)	(319,207)	(142.383)	(703.468)
Eliminate DSM Revenue	DSMREV	>		(14,688)	(16,281)	•	. ''		
Year End Revenue Adjustment	YREND			•	566,077		147.900		•
Adjustment for Merger savings		R01		(51,111)	(67,086)	(21,819)	(123,161)	(54,936)	(271.421)
Adjustment for Customer Rate Switching & CSR Credit	RATESW				,	+		(279,699)	(252,228)
VD1 Amortization and Surcredit		VDTREV		815	1,070	349	1,955	867	4,284
Total Pro-Forma Operating Revenue			v)	13,411,062 \$	18,092,102 \$	5,730,245 \$	31,672,632 \$	14,878,396 \$	72,667,290

Description	Ref Na	Лате	Allocation Vector	Kate LP-100 Secondary	Street Lighting Rate PSL	Street Lighting Rate SLE	Street Lighting Rate OL	Street Lighting Rate TLE	Special Contracts
Cost of Service Summary ~ Pro-Forma									
Operating Revenues									
Total Operating Revenue – Actual				\$ 2,662,246 \$	5,749,261 \$	201,481 \$	6,951,301 \$	717,841 \$	38,877,550
Pro-Forma Adjustments:									
Eliminate unbilled revenue		-	R01	\$ (6,454) \$	(15,890) \$	(464) \$	(19,577) \$	(1.786) \$	(90.792)
Mismatch in fuel cost recovery		-	Energy	(16,458)	(19,759)	(1,535)	(20,526)	(4.410)	(282,033)
To Reflect a Full Year of the FAC Roll-In	Ę	FACRI		1,436	(3,891)	156	(1,432)	161	23.036
Remove ECR revenues	С Ш	ECRREV		(40,296)	(98,342)	(3,010)	(121,526)	(11,097)	(543,453)
To Reflect a Full Year of the ECR Roll-In	Ш Ш	ECRRI		3,088	6,611	212	9,072	811	33,157
Remove off-system ECR revenues			PLPPT	(5,999)	(5,475)	(442)	(5,675)	(1,141)	(86,275)
Eliminate brokered sales			Energy	(84,446)	(101,383)	(7,875)	(105,321)	(22,630)	(1.447,143)
Eliminate ESM revenues	ESI	ESMREV		(20,232)	(57,193)	(1,416)	(65,875)	(6.308)	(335.874)
Eliminate Rate Refund Acct			R01	(24,719)	(60,854)	(1,778)	(74,974)	(6.841)	(347.716)
Eliminate DSM Revenue	SO	OSMREV						-	
Year End Revenue Adjustment	ΥR	YREND		,	2,999	(1,159)	17,114	5,808	
Adjustment for Merger savings			R01	(9,537)	(23,479)	(686)	(28,928)	(2,639)	(134,160)
Adjustment for Customer Rate Switching & CSR Credit	R	RATESW		•		,	ı		(000'06)
VDT Amortization and Surcredit		_	VDTREV	146	364	5	453	41	2,148
Total Pro-Forma Operating Revenue			ŝ	2,458,774 \$	5,372,969 \$	183,495 \$	6,534,107 \$	668,445 \$	35,578,445

Cost of Service Study	Class Allocation
	Cost of Service Study

Class Allocation 11 Months Foded

12 Months Ended September 30, 2003

Conditioned services Image: service se	Description	Ref Name	Allocation e Vector		Total System	Residential Rate R	Water Heating Rate WH	General Service Rate GS	Rate LC Primary	Rate LC Secondary
	Cost of Service Summary - Pro-Forma									
Multimonic ferention Image: Section se	Operating Expenses									
	Operation and Maintenance Expenses			S.						000 760 000
Contract	Depreciation and Amortization Expenses			•						52,753,009 13 036 448
$ \begin{array}{cccccccccccccccccccccccccccccccccccc$	Accretion Expense				462,519	205,902	277	55,493	4.749	000.67
or $(132,06)$ $(132,06)$ $(132,06)$ $(232,06)$ <td>Property and Other Taxes</td> <td></td> <td>NPT</td> <td></td> <td>12,603,252</td> <td>6,103,343</td> <td>40,239</td> <td>1,552,358</td> <td>109,326</td> <td>1,858,537</td>	Property and Other Taxes		NPT		12,603,252	6,103,343	40,239	1,552,358	109,326	1,858,537
	Amortization of Investment Tax Credit				(4,010,380)	(1,942,096)	(12,804)	(493,964)	(34,788)	(591, 390)
	Curter Expenses				(6,055,342)	(2,932,404)	(19,333)	(745,844)	(52,526)	(892,950)
Answer Consisting and answer (13) (13) (13) (13) (13) (13) (13) (13)	State and redetal income (axes Specific Assimptions of Internations of the		TXINCPF		27,184,243 \$	(2,267,328) \$		7,957,650 \$	563,172 \$	8,342,628
Operating Expense Operating Expense Operating Expense (0.046) (2.33,63) (2.	Allocation of interruptible Credits		SCP		(3,519,894) 3,519,894 \$. 69	514.921 \$		- 625 034
and and <td>Adjustments to Obarating Exnerces</td> <td></td> <td></td> <td></td> <td></td> <td></td> <td></td> <td></td> <td>-</td> <td></td>	Adjustments to Obarating Exnerces								-	
metric contraction control control <thcontro< th=""> control <thcontrol< th=""></thcontrol<></thcontro<>	regramments to Operating Expenses. Filminate mismatch in trial cost recovery				e 1000 100 00					
Description Constrain Constrain <thconstrain< th=""> <thconstrain< th=""> <t< td=""><td>Remove FCR extremtees</td><td></td><td>crergy cropool</td><td></td><td>(Z,D05,300) S</td><td>(6/3,190) \$</td><td>(3,045) \$</td><td>(233,620) \$</td><td></td><td>(360,271)</td></t<></thconstrain<></thconstrain<>	Remove FCR extremtees		crergy cropool		(Z,D05,300) S	(6/3,190) \$	(3,045) \$	(233,620) \$		(360,271)
Constraint Constra	Eliminate brokered sales expenses		Frerry		(1,700,344) 4 (35,030,766) 6		(2,41/) \$	(Z56,48/) \$	_ .	(305,205)
and the number of control of	Eliminate DSM Expenses		DSMRFV		(20,000,000) U	a (002/701/0)	e feinioci	(Z'310'1'4) \$		(4,497,006) (040,740)
$ \begin{array}{c c c c c c c c c c c c c c c c c c c $	Year end Expense adjustment		YREND		1.458 544 \$	687 488 5	(5 575) ¢	(108/020) *	_	(340,54U) 520,420
Calibor DET 1 6 45 3 45 3 45 3 45 3 45 3 45 3 45 3 45 3 45 3 45 3 45 3 45 3 45 3 45 3 45	Adjustment to annualize depreciation expense		DET		8,959,741 \$	4.369.417 \$	30 124 \$	1 106 077 \$	76.478	1 201 012 1
Image: Constant of the life protect of the	Depreciation adjustment		DET		· • •			• • •	e ∉	
$ \begin{array}{c c c c c c c c c c c c c c c c c c c $	Labor adjustment		LBT		918,580 \$	451,626 \$	3,076 \$	118.654 \$		130.564
dendage adminimum SIALL $70,422$ $46,703$ $56,45$ 5 $9,461$ 5 2233 5 2336 5 $9,461$ 5 2233 5 2336 5 367 5 2333 5 2333 5 2333 5 2333 5 2333 5 2333 5 367 5 6024 5 2373 5 2373 5 2373 5 2373 5 2373 5 2373 5 2373 5 2373 5 2373 5 2373 5 2373 5 2373 5 2373 5 2373 5 2373 5 23733 5 23733 5 23733 5 237333 237333 237333 237333 237333 237333 237333 237333 237333 2373333 2373333 2373333 2373333 2373333 2373333	Adjustment for pension and post Ret Exp. (See Functional A	ssignment)					•			
$ \begin{array}{c c c c c c c c c c c c c c c c c c c $	Storm damage adjustment		SDALL		70,492 \$	46,793 \$	694 \$		283 \$	5,995
$ \begin{array}{c c c c c c c c c c c c c c c c c c c $	Adjustment to eliminate advertising expense (See Functions	l Assignment)								
$ \begin{array}{c c c c c c c c c c c c c c c c c c c $	Amortization of ECM and a case expenses		OMT		333,580 \$		754 \$		3,739 \$	54,331
$ \begin{array}{c c c c c c c c c c c c c c c c c c c $	Parried uzauori or tudiik, cost (Cos Euroficana) Azaimanti.		КUI		58,333 \$		76 \$		667 \$	10,071
$ \begin{array}{c c c c c c c c c c c c c c c c c c c $	Adjustment for injuries and damages (See Functional Assim	ment)								
Imach for merger savings LET 19,477,401 5 9,551,612 5 6,502 5 2,503,15 5 7,752 5 7,755 5 7,755 5 7,755 5 7,755 5 7,755 5 7,755 5 7,755 5 7,755 5 6,102 5 7,755 7 7 7 7 7	Adjustment for VDT net savings to shareholders		LBT		5 640 000 \$	3 777 GAA	18 888 ¢	748 547 6	E0 010 @	004 000
Image: montradio expenses LBT $(7.72,00)$ $(7.13,0)$ (7.16) $(7$	Adjustment for merger savings		i la l		19.477.401 \$	9 551 612 S	65 067 &		20-047 4	700,100
Schedule 10 one time credit DELT 709,577 315,887 315,887 365 36,156 7255 45,056 7255 45,056 7255 45,056 7255 45,056 7255 45,056 57,75 52,5733 17,755 56,156 57,735 56,156 57,2152 57,735 56,156 57,2152 57,735 56,166 57,735 56,156 57,2152 57,735 56,156 57,2152 57,755 56,156 57,2152 57,755 52,152 57,755 52,152 57,755 52,152	Adjustment for merger amortization expenses		LBT		(2.722.005) \$	_	(9,116) \$	(351 605) \$	5 125 VCJ	0000,101,2
ment currulative effect of accounting change DET 5,280,900 \$ 2,575,353 \$ 17,755 \$ 651,924 \$ 45,076 \$ 7 ment four frast reduction PLPT (2,153,14) \$ (1,446) \$ (383,13) \$ (383,13) \$ (383,13) \$ (383,13) \$ (383,13) \$ (386,073) \$ (383,13) \$	MISO Schedule 10 one time credit		PLTRT		709,577 \$		885 \$	85 136 \$	7 285 5	(150,000)
ment for Tarling frequency LBT (4,13,13,13,13,13,13,13,13,13,13,13,13,13,	Adjustment cumulative effect of accounting change		DET		5,280,909 \$	2,575,353 \$	17,755 \$	651924 \$	45.076 \$	768.013
We Alsom Expenses PLPPT (2,157,640) \$ (360,530) \$ (2,563) \$ (2,563) \$ (2,563) \$ (2,512) \$ (10,140) We Alsom Expenses ET (1,373,630) \$ (360,530) \$ (2,563) \$ (2,512) \$ (1,136) \$ (1,136) ment for convolute entereant ET (1,373,630) \$ (4,36) \$ (19,140) \$ (1,133) \$ (2,512) \$ (2,123) \$ (2,123)	Adjustment for IT staff reduction		LBT		(431,834) \$	(212,314) \$	(1,446) \$	(55,781) \$	(3,893) \$	(61,379)
ment for consider fine mentanoy write-off PLT (1,373,532) 5 (4366) 5 (169,146) 5 (11,386) 5 (2000) 5 2 <th2< th=""> 2</th2<>	Kemove Alstom Expenses		PLPPT		(2, 157,640) \$	(960,530) \$	(2,693) \$	(258,876) \$	(22,152) \$	(368,533)
ment for carbonale masks LBT 17,89,420 5 6,023 5 222,304 5,612.15 5 22 36,204 5,612.15 5 22 36,204 5,612.15 5 16,112 5 22 36,123 5 16,512 5 16,512 5 22 36,813 5 12 5 22 36,813 5 12 5 22 16,5043 5 16,5043 5 12,515,53 5 12 5 22 36,833 5 12 5 22 26,93 5 12 5 12 5 12 5 12 5 12 5 12 5 12 5 12 5 12 5 12 5 12 5 12 5 13 5 13 5 13 13 13 13 13 13 13 13 13 13 13 13 13 13 13 13 13 <td>Adjustment for Upsolete inventory write-off</td> <td></td> <td>PLT</td> <td></td> <td>(1,373,632) \$</td> <td>(666,073) \$</td> <td>(4,386) \$</td> <td>(169,149) \$</td> <td>(11,886) \$</td> <td>(202,133)</td>	Adjustment for Upsolete inventory write-off		PLT		(1,373,632) \$	(666,073) \$	(4,386) \$	(169,149) \$	(11,886) \$	(202,133)
The for Cardione mine with control and with mine with control and with control and with control and with with control and with control and with control and with control and with with control and with with control and with with control and with contro and with control and with control and with control and with con	Adjustment for corporate once lease		181 7		1 798,420 \$	884,205 \$	6,023 \$	232,304 \$	16,212 \$	255,622
Montantingan Turbit 3.388,00 5 1,397,38 5 4,478 5 4,078 5 36,388 5 61 Montantion and Surredit VDTREV 3.388,00 5 1,397,38 5 4,378 5 4,378 5 36,388 5 6 Adjustments VDTREV 7,384,614 7,180,217 78,667 5 1,216,549 (66,587) 5 7 Adjustments TOE 5 641,996,290 5 282,596,495 5 1,289,073 8 33,222,612 5 7,078,563 5 106,65 Iconne – Pro-Forma 5 641,996,290 5 282,596,495 5 1,289,073 5 33,222,612 5 7,078,563 5 106,65 Iconne – Pro-Forma 5 641,996,2562 8 3,330,967 5 135,6600 5 15,623,243 5 10,662 Iconne – Pro-Forma 5 1,473,843,556 5 713,607,594 5 15,774,917 5 216,16 Base 6 6,656 6 6,657 5 1,174 -7,344 5 12,774,917 5 216,14	Aujustment for Anno Bux manit refund		Energy		(1,416,711) \$	(475,597) \$	(2,152) \$	(165,048) \$	(18,755) \$	(254,525)
Adjustments Close 1 Close 1 </td <td>VDT Amortization and Surreality</td> <td></td> <td></td> <td></td> <td>3,000,588,50</td> <td>1,597,293 \$</td> <td>4,478 S</td> <td>430,492 \$</td> <td>36,838 \$</td> <td>612,844</td>	VDT Amortization and Surreality				3,000,588,50	1,597,293 \$	4,478 S	430,492 \$	36,838 \$	612,844
Moleculation 7,150,217 78,687 1,216,549 (66,587) 53 Expenses I CE \$ 641,996,290 282,596,495 \$ 1,289,073 \$ 83,222,612 \$ 7,078,563 \$ 106,65 Income – Pro-Forma \$ 641,996,290 \$ 282,596,495 \$ 1,289,073 \$ 83,222,612 \$ 7,078,563 \$ 106,65 Income – Pro-Forma \$ 67,635,652 \$ 8,338,967 \$ (350,660) \$ 15,623,243 \$ 1,104,627 \$ 16,83 Base \$ 1,473,843,556 \$ 713,607,594 \$ 4,777,998 \$ 101,588,447 \$ 12,774,917 \$ 216,14 Base \$ 1,473,843,556 \$ 1,174 \$ 1,174 \$ 1,377,998 \$ 161,588,447 \$ 12,774,917 \$ 216,14	Total Expanse Adjustments				¢ 1017-721	\$ (q/q/g)	(286) \$	(32,5/0) \$	(2.549) \$	(38,480)
Fickpenses TOE \$ 641,996,290 \$ 252,596,495 \$ 1,289,073 \$ 8,3,222,612 \$ 7,078,563 \$ 106,66 Income – Pro-Forma \$ 67,635,652 \$ 8,338,967 \$ (350,660) \$ 1,104,627 \$ 16,83 Income – Pro-Forma \$ 1,473,843,556 \$ 713,607,594 \$ 4,777,998 \$ 12,774,917 \$ 216,14 Base 4.594 1,174 -7.344 8,607 1,007,594 \$ 10,588,447 \$ 12,774,917 \$ 216,14					7,834,614	7,150,217	78,687	1,216,549	(66,587)	530,139
Income Pro-Forma \$ 67,635,652 8,338,967 \$ (350,660) \$ 15,623,243 \$ 1,104,627 \$ 16,83 Base \$ 1,473,843,556 \$ 713,607,594 \$ 4,777,998 \$ 101,588,447 \$ 12,774,917 \$ 216,14 Base \$ 4.59% 1.17% -7.34% 8.69% 1.00%	Total Operating Expenses	TOE		\$				83,222,612 \$		106,650,455
Base 5 1,473,843,556 5 713,607,594 5 1,777,998 5 12,774,917 5 216,14 - - - - - - - - 10,607 5 216,14 216,14 216,14 216,14 - - 216,14 216	Net Operating Income – Pro-Forma			69	67,635,652 \$		(350,660) \$	15,623,243 \$		16,830,605
4.59% 1.17% -7.34% 8.60% 1.00%	Net Cost Rate Base			ŝ						216,147,929
4.55% 1.17% -7.34% 8.60% 1.00%	Pate of Patrim	1								
					4.59%	1.17%	-7.34%	8.60%	1.00%	7.79%

Summer Winter CP Prod Trans Allocation All Other KHJC Corrections Included

Exhibit (SJB-9) Page 4 of 6

LOUISVILLE GAS AND ELECTRIC COMPANY	Cost of Service Study	Case A Location
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Description Ref	Name	Allocation Vector		Rate LC-TOD Primary	Rate LC-TOD Secondary	Rate LP Primary	Rate LP Secondary	Rate LP-TOD Transmission	Rate LP-TOD Primary
Cost of Service Summary Pro-Forma									
Operating Expenses									
Operation and Maintenance Expenses Depreciation and Amortization Expenses			67	9,511,059 \$ 1366,543	12,159,165 \$ 2 008 241	4,134,166 \$ 508,840	20,678,871 \$ 3 025 419	12,343,825 \$	55,858,289 7 200 263
Accretion Expense				8,054	11.742	3.433	a, uza, 410 16.743	1,330,861 8.872	42.788
Property and Other Taxes		NPT		182,911	268,597	79,946	402,575	182,811	964,524
Amortization of Investment Tax Credit				(58,203)	(85,468)	(25,439)	(128,100)	(58,171)	(306,913)
Orner Expenses State and Federal Income Tayes		TVINDE	e	(87,881) e37.040 e	(129,050) 4 427 465 5	(38,411)	(193,421)	(87,833)	(463,414)
Specific Assignment of Interruptible Credit			•					1,028,706 \$	3,0/0,003 /1306,833)
Allocation of interruptible Credits		SCP	ŝ	66,076 \$	84,505 \$	29,945 \$	140,138 \$	60,511 \$	270,035
Adjustments to Operating Expenses:									
Eliminate mismatch in fuel cost recovery		Energy	**	(44,786) \$	(54,061) \$	(19,122) \$	\$ (868'96)	(63,230) \$	(273,643)
Remove ECR expenses		ECRREV	**	(32,690) \$	(43,382) \$	(14.011) \$	(79,468) \$	_	(177,854)
Climinate Drokered sales expenses		Energy	<i>с</i> я ((559,033) \$	(674,807) \$	(238,687) \$	(1,209,515) \$	(789,257) \$	(3,415,692)
Zilitiliate Dom Experises Year and Exnerse adjustment		USMKEV	1 9 6	(14,699) \$	(16,293) \$, ,		• • •	•
Adjustment to annualize depreciation expense		DET	ъ <i>и</i>	127 759 5	313,014 \$	55 001 6	4 515,25 382 874 5		
Depreciation adjustment		DET	, w	· ·	* ** ,	 	- 10 ¹⁷⁰⁷	\$ 71C'071	417'C/0
Labor adjustment		LBT	υ?	13,432 \$	18,465 \$	6,118 \$	29,754 \$	15,065 \$	74,369
Adjustment for pension and post Ret Exp. (See Functional Assignment)	ent)								-
Storm damage adjustment	:	SDALL	w	454 \$	719 S	221 \$	1,509 \$, ,	2,235
Adjustment to eliminate advertising expense (See Functional Assignment) Amortization of rate rase examinat	ment)	THC.	6		e 000 F	•			
Amortization of ESM audit expenses		E01	n 4	0,244 \$	1,362 3	2./14 \$	13,0/2 5	8,103 S	36,669
Remove one-utility cost (See Functional Assignment)			•		*	, ,		-	60.10
Adjustment for injuries and damages (See Functional Assignment)									
Adjustment for VDT net savings to shareholders		LBT	ŝ	82,472 \$	113,376 \$	37,562 \$	182,687 \$	92,496 \$	456,617
Adjustment for merger savings		181	ю (284,080 \$	390,532 \$	129,386 \$	629,280 \$	318,611 \$	1,572,851
Aujosument turimerge: amonization expenses MISO Schadula 10 one time cradit			*	(38,803) \$	(24,/15) \$	(18,128) \$	(88,169) \$ pr cor \$	(44,641) \$	(220,375)
Adjustment cumulative effect of accounting change		DET	• •	25 TOR 5	110,671 \$	207'C	* 000'C7	13,010 4	05,644 306 705
Adjustment for IT staff reduction		LBT.	• • •	(6.315) \$	(8,681) \$	(2.876) \$	(13.988) \$	(7 D82) \$	330, 1951)
Remove Aistom Expenses		РГРРТ	60	(37,571) \$	(54,776) \$	(16,016) \$	(78,105) \$	(41,386) \$	(199,606)
Adjustment for Obsolete inventory write-off		PLT	6 3	(19,882) \$	(29,199) \$	(8,693) \$	(43,798) \$	(19,838) \$	(104,827)
Adjustment for corporate office lease		LBT	69	26,298 \$	36,152 \$	\$ 776,11	58,253 \$	29,494 \$	145,601
Adjustment for carbide lime write-off		Energy	69 1	(31,641) \$	(38,193) \$	(13,509) \$	(68,457) \$	(44,671) \$	(193,324)
Adjustifiely for Carle Kun repair retund V/DT Amontization and Surveativ		PLPP VICTORV	ю ь	62,479 \$	91,089 \$	26,634 S	129,883 \$	68,821 \$	331,931
Total Evenese Adjustments		AUREA	9	(4,110) 3. (00 COT)	\$ [J040]	6 1707 1	(9.6/4) \$	[4,361] \$	(21.640)
				(98,565)	312,480	(23,471)	(82,931)	(301,556)	(880,258)
Total Operating Expenses	TOE		÷	11,727,934 \$	15,767,670 \$	5,074,656 \$	26,580,591 \$	12,892,066 \$	64,965,374
Net Operating Income - Pro-Forma			••	1,683,128 \$	2,324,432 \$	655,589 \$	5,092,041 \$	1,986,330 \$	7,701,916
Net Cost Rate Base			65	21,350,378 \$	31,196,075 \$	9,346,178 \$	47,140,776 \$	21,464,989 \$	113,070,176
					tite t				
			-	V.98./	SLOP')	%107	10.80%	9.25%	6.81%

Summer Winter CP Prod Trans Allocation All Other KJUC Corrections Included

Exhibit (SJB-9) Page 5 of 6

Description	Name	Allocation Vector		Rate LP-TOD Secondary	Street Lighting Rate PSL	Street Lighting Rate SLE	Street Lighting Rate OL	Street Lighting Rate TLE	Special Contracts
Cost of Service Summary – Pro-Forma									
Operating Expenses									
Operation and Maintenance Expenses			e	1664324 \$	2 829 284 \$	147622 \$	3 156 338 \$	415.971 \$	96 272 879
Depreciation and Amortization Expenses			•		1,257,160	20,945	1,619,639	51,847	3,418,925
Accretion Expense				1,438	1,312	106	1,360	273	20,676
Property and Other Taxes		NPT		35,807	154,958	2,765	198,916	6,870	458,770
Amortization of Investment Tax Credit				(11.394)	(49,308)	(880)	(63,295)	(2,186)	(145,982)
Other Expenses			,	(17.204)	(74,451)	(1,329)	(95,571)	(3,301)	(220,420)
State and Federal income Taxes		LXINCPF		168.316 \$	301,407 \$	4,164 \$	422,25/ \$	72,220 \$	2,1/2,191
Specific Assignment of Interruptible Credit Allocation of Interruptible Credits		SCP	\$	12,085 \$	9 1	9	••	1,678 \$	(486,000) 159,682
Adjustments to Operating Expenses:									
Eliminate mismatch in the cost recovery		Energy	ы	(7,490) \$	(8,992) \$	(eee) \$	(9,342) \$	(2,007) \$	(128,357)
Remove ECR expenses		ECREV	6 9	(6,339) \$	(15,470) \$	(474) \$	(19,117) \$	(1,746) \$	(85,491)
Eliminate brokered sales expenses		Energy	\$	(93,494) \$	(112,246) \$	(8,719) \$	(116,606) \$	(25,054) \$	(1,602,194)
Eliminate DSM Expenses		DSMREV	\$9	ۍ ۲	••	, ,	• • >	۶ ۵	
Year and Expense adjustment		YREND	69 (•0) + - - -	1,673 \$	(647) \$	9,548 \$	3,240 \$, , , ,
Adjustment to annualize depreciation expense		DET	69 (25,247 5	117,542 5	1,958 \$	151,433 \$	4,848 \$	319,663
ueprecialion acquisiment Labor adjustment			A 4		5 178 6		5 738 C		34 067
Adjustment for persion and nost Ret Evo. (See Functional Assimment)		9	ð	¢ 1+C'7	• D71 °C	•		e 700	100,40
Storm damage adjustment		SDAL	ы	164 \$	487 \$	15 \$	508 \$	27 \$	896
Adjustment to eliminate advertising expense (See Functional Assignment)	int)	1	•		•	2		•	2
Amortization of rate case expenses		OMT	¢	1,093 \$	1,857 \$	5 26	2,072 \$	273 \$	17,247
Amortization of ESM audit expenses		R01	⇔	202 \$	496 \$	15 \$	612 \$	20 \$	2,837
Remove one-utility cost (See Functional Assignment)									
Adjustment for injuries and damages (See Functional Assignment)		10	•						000 1 10
Adjustment for VUI net savings to shareholders				15,600 S	31,486 \$	1,320 \$	35,234 5	3,665 \$	214,633
Adjustment for merger savings			96	53,734 5	108,457 5	4,54/ 8	121,365 \$	12,623 \$	/ 39,321
Aujusunent tui merger antuuzauun expenses MIS/C Schadula 10 yoo time medit			.	e (676')	e /oci/ci)	() (02/) 3	2 086 5	420 \$	21 721
Adjustment cumulative effect of accounting change		DFT DFT	•	14 881 \$	69.280 5	1154 5	2,000 \$ 89,255 \$	2.857 \$	188.411
Adjustment for IT staff reduction		LBT	. 49	(1.194) \$	(2.411) \$	(101) \$	(2.698) \$	(281) \$	(16.434)
Remove Alstom Expenses		PLPPT	5	(6.706) \$	(6.121) \$	(494) \$	(6.344) \$	(1.276) \$	(96,454)
Adjustment for Obsolete inventory write-off		PLT	\$	(3,898) \$	(17,059) \$	(301) \$	(21,916) \$	(748) \$	(49,847)
Adjustment for corporate office lease		LBT	69	4,974 \$	10,040 \$	421 S	11,235 \$	1,169 \$	68,440
Adjustment for carbide lime write-off		Energy	ŝ	(5,292) \$	(6,353) \$	(493) \$	(6,600) \$	(1,418) \$	(90,682)
Adjustment for Cane Run repair refund		PLPPT	69	11,152 \$	10,178 \$	821 \$	10,550 \$	2,121 \$	160,397
VDT Amortization and Surcredit		VDTREV	\$	(738) \$	(1.836) \$	(52) \$	(2.290) \$	(206) \$	(10.853)
Total Expense Adjustments				(888)	172,954	(1,891)	237,721	(2,609)	(405,376)
Total Operating Expenses	TOE		v 3	2,122,511 \$	4,593,316 \$	171,503 \$	5,477,363 \$	540,763 \$	31,245,346
Net Operating income			67	336,263 \$	779,653 \$	11,992 \$	1.056.745 \$	127,683 \$	4,333,099
Net Cost Rate Base			÷	4,185,391 \$	18,541,750 \$	325,889 \$	23,816,316 \$	813,020 \$	53,695,734
Rate of Refum				8 03%	4 20%	3.68%	4.44%	15.70%	8 07%
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Summer Winter CP Prod Trans Allocation All Other KIUC Corrections Included

Exhibit (SJB-9) Page 6 of 6

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

IN THE MATTER OF:

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

EXHIBIT (SJB-10)

LOUISVILLE GAS AND ELECTRIC COMPANY	Case Allocation
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Description	Ref Name	Allocation Vector		Total Svstem	Residential Rate R	Water Heating Pate WH	General Service	Rate LC	Rate LC
						LARCE LEL	Vale CO	r IIItal y	Secondary
Cost of Service Summary – Pro-Forma									
Operating Revenues									
Totai Operating Revenue – Actual			\$	768,525,785 \$	292,624,282 \$	999,032 \$	108,199,109 \$	8,991,845 \$	133,330,572
Pro-Forma Adjustments:									
Eliminate unbilled revenue		R01	\$	(1,867,000) \$	(715,724) \$	(2.428) \$	(271 251) \$	(21339) \$	(125 222)
Mismatch in fuel cost recovery		Energy		(4,406,145)	(1,479,166)	(6,691)	(513, 321)	(58.331)	(791 604)
To Reflect a Full Year of the FAC Roll-In	FACRI			547,241	181,639	1,202	87,109	11 617	139 923
Kemove ECK revenues	ECRREV			(11,228,429)	(4,264,952)	(15,362)	(1,630,456)	(127,642)	(1.940,152)
Io Kettect a Full Year of the ECR Roll-In	ECRRI			723,260	255,297	937	110,897	9,089	133,401
Kemove off-system ECR revenues		PLPPT		(1,929,923)	(828,562)	(1,405)	(282,326)	(22,779)	(342,700)
climinate brokered sales				(22,608,445)	(7,589,772)	(34,335)	(2,633,910)	(299,304)	(4,061,814)
	ESMREV			(6,974,780)	(2,763,963)	(7,154)	(1,009,115)	(80,480)	(1, 196, 285)
Eliminate Rate Retund Acct		R01		(7,150,231)	(2,741,076)	(8,299)	(1,038,835)	(81.725)	(1.234.463)
Eliminate DSM Revenue	DSMREV	~		(3,277,501)	(2,771,657)	•	(108,973)	(25,623)	(340.279)
Year End Revenue Adjustment	YREND			2,614,347	1,232,278	(8,993)	(279,531)		932.854
Adjustment for Merger savings		R01		(2,758,795)	(1,057,598)	(3,588)	(400,817)	(31 532)	(476 296)
Adjustment for Customer Rate Switching & CSR Credit	RATESW			(621,927)	•				
VDT Amortization and Surcredit		VDTREV		44,485	17,356	57	6,447	505	7,617
Total Pro-Forma Operating Revenue			¢	a 010 100 002					

LOUISVILLE GAS AND ELECTRIC COMPANY	Cust of Service Study Class Allocation
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Class Allocation

12 Months Ended September 30, 2003

Description	Pof Name	Allocation		Rate LC-TOD	Rate LC-TOD	Rate LP	Rate LP	Rate LP-TOD	Rate LP-TOD
		101334			Secondary	FIRMUY	seconoary	Iransmission	Primary
Cost of Service Summary – Pro-Forma									
Operating Revenues									
Total Operating Revenue Actual			s	14,661,285 \$	18,923,999 \$	6,286,088 \$	34,365,122 \$	16,503,526 \$	78,762,216
Pro-Forma Adjustments:									
Eliminate unbilled revenue		R01	\$9	(34,589) \$	(45,400) \$	(14,766) \$	(83.348) \$	(37,178) \$	(183,683)
Mismatch in fuel cost recovery		Energy		(98,406)	(118,786)	(42,016)	(212,910)	(138,932)	(601 261)
To Reflect a Full Year of the FAC Roll-In	FACRI			16,117	24,738	5,030	28,206	10,866	20.692
Kemove ECK revenues	ECRREV	~		(207,809)	(275,776)	(89,065)	(505,167)	(223,730)	(1,130,594)
to reflect a Full Year of the ECR RolHin	ECRRI			14,884	21,249	5,484	35, 195	16,754	67,122
Kemove off-system ECR revenues		PLPPT		(36,229)	(46,333)	(16,419)	(76,836)	(33,178)	(148,058)
Eliminate brokered sales				(504,933)	(609,504)	(215,588)	(1,092,466)	(712,877)	(3,085,143)
cilminate ESM revenues	ESMREV			(130,047)	(164,826)	(53,219)	(301,827)	(135,771)	(645,195)
Eliminate Rate Refund Acct		R01		(132,469)	(173,873)	(56,551)	(319,207)	(142.383)	(703.468)
Eliminate OSM Revenue	DSMREV	>		(14,688)	(16.281)		. '		
Year End Revenue Adjustment	YREND				566,077	,	147,900		
Adjustment for Merger savings		R01		(51,111)	(67,086)	(21,819)	(123, 161)	(54.936)	(271.421)
Adjustment for Customer Rate Switching & CSR Credit	RATESW				•	•	· · ·	(279,699)	(252.228)
VDT Amortization and Surcredit		VDTREV		815	1,070	349	1,955	867	4,284
Total Pro-Forma Operating Revenue			ы	13,482,820 \$	18,019,270 \$	5,787,507 \$	31,863,456 \$	14,773,330 \$	71,833,262

LOUISVILLE GAS AND ELECTRIC COMPANY	Cost of Service Study Class Allocation
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Description	Ref Name	Allocation Vector		Rate LP-TOD Secondary	Street Lighting Rate PSL	Street Lighting Rate SLE	Street Lighting Rate OL	Street Lighting Rate TLE	Special Contracts
Cost of Service Summary - Pro-Forma									
Operating Revenues									
Total Operating Revenue Actual			59	2,680,042 \$	5,593,988 \$	188,954 \$	6,790,363 \$	711,578 \$	38,913,781
Pro-Forma Adjustments:									
Eliminate unbilled revenue		R01	\$	(6,454) \$	(15,890) \$	(464) \$	(19,577) \$	(1,786) \$	(90.792
Mismatch in fuel cost recovery		Energy		(16,458)	(19,759)	(1,535)	(20,526)	(4,410)	(282,033
To Reflect a Full Year of the FAC RolHn	FACRI			1,436	(3,891)	156	(1,432)	161	23,036
Remove ECR revenues	ECRREV			(40,296)	(98,342)	(3,010)	(121,526)	(11,097)	(543,453
To Reflect a Full Year of the ECR Roll-In	ECRR			3,088	6,611	212	9,072	811	33,157
Remove off-system ECR revenues		PLPPT		(6,626)		,	. '	(920)	(87,552
Eliminate brokered sales		Energy		(84,446)	(101,383)	(7,875)	(105.321)	(22,630)	(1.447,143)
Eliminate ESM revenues	ESMREV			(20,232)	(57,193)	(1,416)	(65.875)	(8,308)	(335,874
Eliminate Rate Refund Acct		R01		(24,719)	(60,854)	(1.778)	(74.974)	(6.841)	(347.716
Eliminate DSM Revenue	OSMREV	_			. '	-		-	
Year End Revenue Adjustment	YREND				2,999	(1,159)	17.114	5.808	,
Adjustment for Merger savings		RO1		(9,537)	(23.479)	(686)	(28.928)	(2 639)	(134 160
Adjustment for Customer Rate Switching & CSR Credit	RATESW				,				000 06/
VDT Amortization and Surcredit		VDTREV		146	364	0	453	41	2,148
Total Pro-Forma Operating Revenue			5	2,475,943 \$	5,223,172 \$	171,410 \$	6,378,844 \$	662,403 \$	35,613,399

Summer CP Prod Trans Allocation All Other KIUC Corrections Included

Description	af Name	Allocation & Vector		Totai System	Residential Rate R	Water Heating Rate WH	General Service Rate GS	Rate LC Primary	Rate LC Secondary
Cost of Service Summary – Pro-Forma									
Operating Expenses									
Oneration and Maintenance Evnances			ť	\$ UCA 018 13	205 B61 355 €	1 D78 705 \$	64 050 504 ¢	5 007 311 \$	83 605 315
Denrectation and Amortization Expenses			•	05 827 065	45.621.527				14 410 830
Accretion Expense				462.519	198.570	337	67.661	5.459	82,130
Property and Other Taxes		NPT		12 603 252	5 852 910	35.308	1 802 008	123,902	1 922 763
Amortization of Investment Tax Credit				(4.010.380)	(1.894.228)	(11.235)	(573,403)	(39.426)	(611.827)
Other Expenses				(6,055,342)	(2 860 128)	(16.964)	(865 791)	(23, 230)	(923 808)
State and Federal Income Taxes		TXINCPF		27,184,243 \$	(1.043,177) \$	(231,209) \$	5.926,115 \$	444.554 \$	7,819,988
Specific Assignment of Interruptible Credit				(3,519,894)				•	•
Allocation of Interruptible Credits		SCP		3,519,894 \$	1,511,175 \$	2,563 \$	514,921 \$	41,545 \$	625,034
Adjustments to Operating Expenses:									
Eliminate mismatch in fuel cost recovery		Energy		(2,005,300) \$	(673,190) \$	(3,045) \$	(233,620) \$	(26,547) \$	(360,271)
Remove ECR expenses		ECRREV		_	_	(2,417) \$	(256,487) \$	(20,079) \$	(305,205)
Eliminate brokered sales expenses		Energy		(25,030,766) \$	(8,402,958) \$	(38,013) \$	(2,916,114) \$	(331,372) \$	(4,497,006)
Eliminate DSM Expenses		DSMREV		(3,280,013) \$	(2,773,781) \$	• ,	(109,057) \$	(25,643) \$	(340,540)
Year end Expense adjustment		YREND		1,458,544 \$	687,488 \$	(5.575) \$	~	5	520,439
Adjustment to annualize depreciation expense		DET		8,959,741 \$	4,265,530 \$	26,719 \$	1,278,478 \$	86,544 \$	1,347,386
Depreciation adjustment		DET		•	•••	•••	(A)	ю) ,	
Labor adjustment		LBT		918,580 \$	444,635 \$	2,847 \$	130,256 \$	8,958 \$	133,549
Adjustment for pension and post Ret Exp. (See Functional Assignment)	iment)								
Storm damage adjustment		SDALL		70,492 \$	46,793 \$	694 S	9,491 \$	283 5	5,995
Adjustment to extrinate auventising expense (See Functional Assignment) Amontization of rate approximations	ignment)	THO		000 EEN &	40E 400 @	707 e	10 C 40	9 070 ¢	54043
Amortization of FSM audit expenses		R01		58.333 \$	22 362 5	4 92 24	8.475 5	9°0'0 4	12011
Remove one-utility cost (See Functional Assignment)		-		+ 000100		2	• •	•	
Adjustment for injuries and damages (See Functional Assignment)	0								
Adjustment for VDT net savings to shareholders		LBT		5,640,000 \$	2,730,022 \$	17,481 \$	799,758 \$		819,977
Adjustment for merger savings		LBT		19,427,401 \$	9,403,764 \$	60,215 \$	2,754,826 \$	189,454 \$	2,824,471
Adjustment for merger amortization expenses		LBT		(2,722,005) \$	(1,317,577) \$	(B,437) \$	(385,983) \$	(26,545) \$	(395,741)
MISO Schedule 10 one time credit		PLTRT		709,577 \$	304,638 \$	517 \$	103,803 \$		126,001
Adjustment cumulative effect of accounting change		DET		5,280,909 \$	2,514,121 \$	15,748 \$	753,540 \$	51,009 \$	794,155
Adjustment for II staff reduction				(431,834) \$	(209,028) \$	(1,338) \$	(61,235) \$	(4,211) \$	(62,783)
Kemove Alstom Expenses		PLPP1		(2,157,64U) \$	(926,327) \$	(1/9/1) S	(315,638) \$	(797'92)	(383, 136)
Adjustment for Cosoiete Inventory white-off		2		(1,3/3,632) \$	(05/,649) 570,750	S (059'5)	(196,237) \$	(13,45/) \$	(201, 602)
		<u> </u>		0 111L 011 11		0,0/14 0,0	4 010102 1010	000°/1	COH 107
Aujustrien in Carologe ime write-on Adjustrien far Caro Dire seads actived		Crergy Dr. DOT							(070'807)
Aujusurien for Carle Run lepain lerunu VOT Amortization and Surveadit		VINTERV		3,300,000 \$	1,04U,4I0 5	2,012 \$	324,004 \$	47.043 A	(38 ASM)
Total Evnense Adjustments				7 834 614	6 778 619	RE SOF	1 823 224	(30 580)	1001-1001
						202122	L04'000'		
Total Operating Expenses	TOE		6 9	641,996,290 \$	260,116,624 \$	1,207,777 \$	87,338,074 \$	7,318,859 \$	107,709,214
Net Operating Income – Pro-Forma			67	67,635,652 \$	9,981,759 \$	(296.805) \$	12,896.954 \$	945,443 \$	16,129,229
Net Cost Rate Base			ŝ	1,473,843,556 \$	696.707,368 \$	4,223,971 \$	209,635,156 \$	14,412,525 \$	223,363,330
Date of Detrime			$\left \right $	A COW	1 421	1 MEN 7	C 4E4/	4 004/	79947
				N 70-1		NOD' 1-	B/ 21-0	27 AN1	2/ 44-1

Summer CP Prod Trans Allocation All Other KUUC Corrections Included

Exhibit (SJB-10) Page 4 of 6

LOUISVILLE GAS AND ELECTRIC COMPANY	Cost of Service Study	Class Allocation
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Description, Ref	Name	Allocation Vector		Rate LC-TOD Primary	Rate LC-TOD Secondary	Rate LP Primary	Rate LP Secondary	Rate LP-TOD Transmission	Rate LP-TOD Primary
Cost of Service Summary – Pro-Forma									
Operating Expenses									
Operation and Maintenance Expenses			y	0 608 753 ¢	41 060 460 ¢	4 700 EA7 &	4 110 011 PC		
Depreciation and Amortization Expenses			•				3 278 713	1211500	200,2002,002 A D03,275
Accretion Expense				8.682	11 104	3 935	18 414	7 051	137 CEA 25
Property and Other Taxes		NPT		195.807	255,508	90 236	436.868	163 929	R14 639
Amortization of Investment Tax Credit				(62,306)	(81,303)	(28.713)	(139.012)	(52,163)	(259,220)
Other Expenses				(94,077)	(122,761)	(43,355)	(209,897)	[78.761]	(391.401)
State and Federal Income Taxes		TXINCPF	ŝ	733,001 \$	1,243,968 \$	231,896 \$	2,442,236 \$	1,183,356 \$	4,896,552
Specific Assignment of Interruptible Credit				ŗ	,	•	•	(1,637,062)	(1,396,833)
Allocation of Interruptible Credits		SCP	÷	66,076 \$	84,505 \$	29,945 \$	140,138 \$	60,511 \$	270,035
Adjustments to Operating Expenses:									
Eliminate mismatch in fuel cost recovery		Energy		(44.786) \$	(54.061) \$	(19.122) \$	(96 898) \$	\$ (053.230) \$	(173 EAR)
Remove ECR expenses		ECRREV		(32,690) \$	(43.382) \$	(14 011) S	(79.468) \$		(177,854)
Eliminate brokered sales expenses		Energy	\$	(559,033) \$	(674.807) \$	(238.687) \$	(1.209.515) \$	(789.257)	(3 415 692)
Eliminate DSM Expenses		DSMREV	\$	(14,699) \$	(16,293) \$	ю ,			
Year and Expense adjustment		YREND	ψ	\$	315,814 \$	ю ,	82,513 \$	· •	
Adjustment to annualize depreciation expense		DET	6 9	136,675 \$	178,728 \$	63,098 \$	306,554 \$	113,273 \$	569,706
uepreciation adjustment		DET	• •		· •	\$	<i>с</i> э ,	\$	•
Later adjustment for negating and nost Ret Evol (See Functional Assimumant).		5	2	14,031 \$	17,857 \$	6,596 \$	31,348 \$	14,187 \$	67,403
Storm damage adjustment		SDAL	v	454 ¢	710 €	9 PCC	4 EAD &	4	700 0
Adjustment to eliminate advertising expense (See Functional Assignment)	P		•	•	* D			, ,	5,235
Amortization of rate case expenses	-	OMT	63	6,367 \$	7.857 \$	2.812 \$	13 902 \$	7 923 \$	35 240
Amortization of ESM audit expenses		R01	\$	1,081 \$	1,418 \$	461 \$		1,162 \$	5.739
Remove one-utility cost (See Functional Assignment)									
Adjustment for injuries and damages (See Functional Assignment)									
Adjustment for VULL net savings to snareholders			1 29 (86,151 \$	109,641 \$	40,498 \$	192,472 \$	87,109 \$	413,851
Adjustment for mercar americation processo			69 6	296.754 \$	377,668 \$	139,500 \$	662,984 \$	300,054 \$	1,425,542
MISO Schedule 10 me time credit cypenses			A 4	<pre>(2/0,14)</pre>	<pre>\$ (016/2C)</pre>	(19,545) \$	(92,892) \$	(42,041) \$	(199,735)
Adjustment cumulative effect of accounting change			• •	80 557 6	11,030 4	0,U3/ 30	\$ 0.57B2	12, 199 \$	54,437
Adjustment for IT staff reduction		L BT	•	(8 506) \$		21,130 G	00,001 8	00'10+ 4	101,000
Remove Alstom Expenses		РГРРТ	•••	(40.503) \$	(51.800) \$	(18.356) \$	(12/1) (85 GD2) \$	(137 D93) \$	(100/)0/)
Adjustment for Obsolete inventory write-off		PLT	- 63	(21,281) \$	(27.779) \$		(47,519) \$	* (527.10) * (17.789) *	(BR 563)
Adjustment for corporate office lease		LBT	\$	27,471 \$	34.961 \$	12,914 \$	61.373 \$	27.776 \$	131.964
Adjustment for carbide lime write-off		Energy	ы	(31,641) \$	(38,193) \$	(13,509) \$	(68,457) \$	(44,671) \$	(193,324)
Adjustment for Cane Run repair refund		РСРРТ	63 -	67,354 \$	86,140 \$	30,525 \$	142,849 \$	61,682 \$	275,260
		VDTREV	5	(4,116) \$	(5.407) \$	(1.762) \$	(9,874) \$	(4,381) \$	(21,640)
i otal Expense Adjustments				(66,710)	280,149	1,949	1,780	(348,197)	(1,250,502)
Total Operating Expenses	TOE		ø	11,940,518 \$	15,551,903 \$	5,244,297 \$	27,145,913 S	12,580,806 \$	62,494,541
Net Operating Income – Pro-Forma			÷	1,542,302 \$	2,467,367 \$	543,210 \$	4.717.543 \$	2.192.524 \$	9.338.720
Net Cost Kate Base			÷	22,799,127 \$	29,725,634 \$	10,502.278 \$	50,993,425 \$	19,343,767 \$	96,231,548
Rate of Return			ŀ	6 76 V.	7305 8	1742.6.2	0 729/	44 994/	0 Tok
							lar avera	B/ 2011	

Summer CP Prod Trans Allocation All Other KJUC Corrections Included

Exhibit (SJB-10) Page 5 of 6

LOUISVILLE GAS AND ELECTRIC COMPANY	Cost of Service Study	Class Allocation
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Description	Name	Allocation Vector		Rate LP-TOD Secondary	Street Lighting Rate PSL	Street Lighting Rate SLE	Street Lighting Rate OL	Street Lighting Rate TLE	Special Contracts
Cost of Service Summary Pro-Forma									
Operating Expenses									
Oneration and Maintenance Evoluties			6	1 700 110	9 103 BCN C				
Operation and American Expenses			÷	1,703,013 &	2,438,9U/	2 960'911	2, /51, 303 \$	400,208 \$	26,364,063
Accretion Frances				110'767	770'000't	4,904	1,413,540	43,826	3,465,322
Prometty and Other Taxae		404		000.1	-			177	286,02
Amodination of Investment Tex Credit				28,883 1010 011	128,038	550	171,013	5,784	465,052
				(12,3/6)	(40,742)	(183)	(54,417)	(1,840)	(147,980)
					(61.517)	(285)	(82,165)	(2,779)	(223,438)
olate and reueral income axes		LXINCPE		143,208 \$	520,472 \$	21,838 \$	649,315 \$	81,056 \$	2,121,074
Specine Assignment of Interruptible Credit Allocation of Interruntible Credits		aus	÷	10 005 6					(486,000)
		2	•		•	9 1	,	e 0/0'i	700'601
Adjustments to Operating Expenses:									
Eliminate mismatch in fuet cost recovery		Energy	5	(7,490) \$	(8.992) \$	(698) \$	(9.342) \$	(2.007) \$	(128.357)
Remove ECR expenses		ECRREV	- 63	(6.339) \$	(15.470) \$	(474) \$	\$ (10 112) \$		(85.491)
Eliminate brokered sales expenses		Energy	63	(93,494) \$	(112.246) \$	(8.719) \$	(116.606) \$	(25 054) \$	(1 602 194)
Etiminate DSM Expenses		DSMREV	*	ن ه ۱	\$	6 9	-		-
Year end Expense adjustmant		YREND	ю	ъэ ,	1,673 \$	(647) \$	9,548 \$	3,240 \$	'
Adjustment to annualize depreciation expense		DET	ŝ	27,378 \$	98,951 \$	459 \$	132,164 \$		324,001
Depreciation adjustment		DET	69	њэ ,	°,	۰ ،	• •	• •	
Labor adjustment		LBT	ŝ	2,684 \$	3,877 \$	114 \$	4,442 \$	546 \$	35,249
Adjustment for pension and post Ret Exp. (See Functional Assignment)									
Storm damage adjustment		SDALL	ю	164 \$	487 \$	15 \$	508 \$	27 \$	896
Aujusment to eliminate advertising expense (See Functional Assignment) Amoditation of acts accessing	Ê		•			:			!
Amortization of ESM andit avoances		i MO	* •	1,122 \$	1,601 5	76 \$	1,806 \$	263 \$	17,307
Demove one ritiky over (Con Eurodiana) Andreanad		אטו	•	< 7N7	430 \$	2° CL	612 \$	26 \$	2,837
Adjustment for injuries and demanes (See Functional Assimmant)									
Adjustment for VDT net sevence to charabolicate		Ται	÷	16 490 6	9 202 CC	700	8 0FC FC		007 070
Adjustment for mercer savings			9 0	56 766 4	81 000 5	9 C17 C	4 C/7'/7	0,000 0 11,000 0	245,012
Adjustment for merger amortization expenses		BT) vi	(7.954) \$	(11480) 5	2 (338) S	80,342 9 (13 162) 5	(1610) \$	(404 450)
MISO Schedule 10 one time credit		PLTRT	- 67	2.436 \$		5		338.5	32 190
Adjustment cumulative effect of accounting change		DET	*7	16,137 \$	58,322 \$	270 \$	77,898 \$	2.415 5	190.968
Adjustment for 1T staff reduction		LBT	÷	(1,262) \$	(1,823) \$	(54) \$	(2,088) \$	(257) \$	(16,571)
Remove Alstorn Expenses		PLPPT	**	(7,408) \$	• •	\$		(1,029) \$	(97,883)
Adjustment for Obsolete inventory write-off		PLT	**	(4,233) \$	(14,13B) \$	(65) \$	(18,888) \$	(630) \$	(50,529)
Adjustment for corporate office lease		LBT	69	5,255 \$	7,591 \$	223 \$	8,696 \$	1,070 \$	69,011
Adjustment for carbide lime write-off		Energy	69	(5,292) \$	(6,353) \$	(493) \$	(6,600) \$	(1,418) \$	(90,682)
Adjustment for Cane Kun repair retund		PLPPT	69 (12,319 \$	•	•••	, ,	1,711 \$	162,772
		VDTREV	\$	(738) \$	(1,836) \$	(52) \$	(2,290) \$	(206) \$	(10,853)
Total Expense Adjustments				6,734	106,456	(7,256)	168,796	(5,292)	(389,859)
Total Operating Expenses	TOE		¢	2,173,375 \$	4,149,537 \$	135,701 \$	5,017,391 \$	522,862 \$	31,348,898
Net Operating Income – Pro-Forma			ø	302,568 \$	1,073,635 \$	35,709 \$	1,361,453 \$	139,541 \$	4,264,501
Not Cret Pate Bara			ę						
			•	¢ 050/255.4	¢ 90%,/10,01	\$1,900 \$	20,681,627 \$	691,027 \$	54,401,435
Rate of Return				6.68%	6.92%	43.50%	6.58%	20.19%	7.84%

Summer CP Prod Trans Allocation All Other KIUC Corrections Included

Exhibit (SJB-10) Page 6 of 6

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

IN THE MATTER OF:

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

EXHIBIT (SJB-11)

				12 Months Ended September 30, 2003	ded 2003				
Description	Ref Name	Allocation Vector		Total System	Residential Rate R	Water Heating Rate WH	General Service Rate GS	Rate LC Primary	Rate LC Secondary
Cost of Service Summary – Pro-Forma									
Operating Revenues									
Total Operating Revenue – Actual			ю	768,525,785 \$	289,945,333 \$	1,027,181 \$	107,368,029 \$	8,963,998 \$	134, 147, 791
Pro-Forma Adjustments:									
Eliminate unbilled revenue		R01	**	(1,867,000) \$	(715,724) \$	(2,428) \$	(271,251) \$	(21,339) \$	(322,331)
Mismatch in fuel cost recovery		Energy		(4,406,145)	(1,479,166)	(6,691)	(513,321)	(58,331)	(791,604)
To Reflect a Full Year of the FAC RolHin	FACRI			547,241	181,639	1,202	87,109	11,617	139,923
Remove ECR revenues	ECRREV	>		(11,228,429)	(4,264,952)	(15,362)	(1,630,456)	(127,642)	(1,940,152)
To Reflect a Full Year of the ECR Roll-In	ECRRI			723,260	255,297	337	110,897	9,089	133,401
Remove off-system ECR revenues		PLPPT		(1,929,923)	(734,104)	(2,398)	(253,023)	(21,797)	(371,514)
Eliminate brokered sales		Energy		(22,608,445)	(7,589,772)	(34,335)	(2,633,910)	(289,304)	(4,061,814)
Eliminate ESM revenues	ESMREV	S		(6,974,780)	(2,763,963)	(7,154)	(1,009,115)	(80,480)	(1, 196, 285)
Eliminate Rate Refund Acct		R01		(7 150,231)	(2,741,076)	(9,299)	(1,038,835)	(81.725)	(1.234.463)
Eliminate DSM Revenue	DSMREV	S		(3,277,501)	(2,771,657)	•	(108,973)	(25,623)	(340.279)
Year End Revenue Adjustment	YREND			2,614,347	1,232,278	(6,993)	(279,531)		932,854
Adjustment for Merger savings		RO		(2.758.795)	(1.057.598)	(3.588)	(400.817)	(31.532)	(476,296)
Adjustment for Customer Rate Switching & CSR Credit	RATESW	N		(621.927)					

LOUISVILLE GAS AND ELECTRIC COMPANY Cost of Service Study Class Allocation

i oral Operativity Revenue - Actual			\$ \$97,525,897	269,945,333 \$	1,027,187 \$	107,368,029
Pro-Forma Adjustments:						
Eliminate unbilled revenue	R01	**	(1,867,000) \$	(715,724) \$	(2,428) \$	(271.251)
Mismatch in fuel cost recovery	Energy	70	(4,406,145)	(1,479,166)	(6.691)	(513.321)
To Reflect a Full Year of the FAC RolHn			547,241	181,639	1,202	87,109
Remove ECR revenues	ECRREV		(11,228,429)	(4,264,952)	(15,362)	(1.630.456)
To Reflect a Full Year of the ECR Roll-In	ECRRI		723,260	255,297	937	110.897
é		F.	(1,929,923)	(734,104)	(2,398)	(253.023)
Eliminate brokered sales	Energy	0A	(22,608,445)	(7,589,772)	(34,335)	(2,633,910)
Eliminate ESM revenues	ESMREV		(6,974,780)	(2,763,963)	(7,154)	(1.009,115)
Eliminate Rate Refund Acct	R01		(7 150,231)	(2,741,076)	(9,299)	(1.038,835)
Eliminate DSM Revenue	DSMREV		(3,277,501)	(2,771,657)		(108.973)
Year End Revenue Adjustment	YREND		2,614,347	1,232,278	(8,993)	(279,531)
Adjustment for Merger savings	R01		(2.758.795)	(1.057.598)	(3.588)	(400.817)
Adjustment for Customer Rate Switching & CSR Credit	RATESW		(621,927)			
VDT Amortization and Surcredit	VDTREV	REV	44,485	17,356	57	6,447
Total Pro-Forma Operating Revenue		69	709,631,942 \$	267,513,891 \$	938,129 \$	99,433,251

(322.331) (731,604) 139,823 (1940,152) (315,14) (371,514) (371,514) (4,06,1814) (1,196,285) (1,196,285) (1,196,285) (302,295) (302,2796) (302,2796) (302,2796) (302,2796) (302,2796) (302,2796) (302,2796) (302,2796) (302,2796) (302,2796) (302,2796) (302,2796) (302,2796) (302,2796) (302,2796) (302,2796) (302,2796) (302,2796) (302,2797) (302,2

124,626,847

8,237,436 \$

99,433,251 \$

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12 CP Prod Trans Allocation All Other KIUC Corrections Included

LOUISVILLE GAS AND ELECTRIC COMPANY Cost of Service Study Class Allocation

Class Allocation 13 Months Ended

12 Months Ended September 30, 2003

Description	Ref	Name	Allocation Vector		Rate LC-TOD Primerv	Rate LC-TOD Secondary	Rate LP Primary	Rate LP Secondary	Rate LP-TOD Transmission	Rate LP-TOD
Cost of Service Summary Pro-Forma						(interior and	(m			
Operating Revenues										
Total Operating Revenue – Actual				63	14,611,283 \$	19,185,651 \$	6,326,234 \$	34,518,858 \$	16,707,671 \$	80,517,847
Pro-Forma Adjustments:										
Eliminate unbilled revenue			R01	\$	(34,589) \$	(45,400) \$	(14,766) \$	(83.348) \$	(37,178) \$	(183,683)
Mismatch in fuel cost recovery			Energy		(98,406)	(118,786)	(42,016)	(212,910)	(138,932)	(601,261)
To Reflect a Full Year of the FAC Roll-In		FACRI			16,117	24,738	5,030	28,206	10,866	20,692
Remove ECR revenues		ECRREV			(207,809)	(275,776)	(89,065)	(505,167)	(223,730)	(1.130.594)
To Reflect a Full Year of the ECR Roll-In		ECRRI			14,884	21,249	5,484	35,195	16,754	67,122
Remove off-system ECR revenues			PLPPT		(34,466)	(55,559)	(17,834)	(82,257)	(40,376)	(209,960)
Etiminate brokered sales			Energy		(504,933)	(609,504)	(215,588)	(1,092,466)	(712,877)	(3.085.143)
Eliminate ESM revenues		ESMREV			(130,047)	(164,826)	(53,219)	(301,827)	(135,771)	(645,195)
Eliminate Rate Refund Acct			R01		(132,469)	(173,873)	(56,551)	(319,207)	(142,383)	(703,468)
Eliminate DSM Revenue		DSMREV			(14,688)	(16,281)	•	•	. '	. ,
Year End Revenue Adjustment		YREND				566,077	,	147,900		,
Adjustment for Merger savings			Ro1		(51,111)	(67,086)	(21,819)	(123,161)	(24,936)	(271,421)
Adjustment for Customer Rate Switching & CSR Credit		RATESW			,	•	•	•	(279,699)	(252,228)
VDT Amortization and Surcredit			VDTREV		815	1,070	349	1,955	867	4,284
Total Pro-Forma Operating Revenue				s	13,434,580 \$	18,271,695 \$	5,826,237 \$	32,011,772 \$	14,970,276 \$	73,526,990

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LOUISVILLE GAS AND ELECTRIC COMPANY Cost of Service Study Class Allocation
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12 Months Ended September 30, 2003

Description	Ref Name	Allocation Vector		Rate LP-TOD Secondary	Street Lighting Rate PSL	Street Lighting Rate SLE	Street Lighting Rate OL	Street Lighting Rate TLE	Special Contracts
Cost of Service Summary – Pro-Forma									
Operating Revenues									
Total Operating Revenue Actual			цэ	2,662,722 \$	5,655,911 \$	194,251 \$	6,854,604 \$	724,458 \$	39,113,964
Pro-Forma Adjustments:									
Eliminate unbitted revenue		R01	~	(6,454) \$	(15,890) \$	(464) \$	(19,577) \$	(1,786) \$	(90,792)
Mismatch in fuel cost recovery		Energy		(16,458)	(19,759)	(1,535)	(20,526)	(4,410)	(282,033)
To Reflect a Fult Year of the FAC Roll-In	FACRI			1,436	(3,891)	156	(1,432)	197	23,036
Remove ECR revenues	ECRREV	2		(40,296)	(98,342)	(3,010)	(121,526)	(11,097)	(543,453)
To Reflect a Full Year of the ECR RolLin	ECRRI			3,088	6,611	212	9,072	811	33,157
Remove off-system ECR revenues		PLPPT		(6,015)	(2,183)	(187)	(2,265)	(1,374)	(94,610)
Eliminate brokered sales		Energy		(84,446)	(101,383)	(7,875)	(105,321)	(22,630)	(1,447,143)
Eliminate ESM revenues	ESMREV			(20,232)	(57,193)	(1,416)	(65,875)	(6,308)	(335,874)
Eliminate Rate Refund Acct		R01		(24,719)	(60,854)	(1,778)	(74,974)	(6,841)	(347,716)
Eliminate DSM Revenue	DSMREV	2					•	•	•
Year End Revenue Adjustment	YREND			,	2,999	(1,159)	17,114	5,806	•
Adjustment for Merger savings		R01		(8,537)	(23,479)	(686)	(28,928)	(2.639)	(134,160)
Adjustment for Customer Rate Switching & CSR Credit	RATESW	W		•	•	•		F	(000'06)
VDT Amortization and Surcredit		VDTREV		146	364	6	453	41	2,148
Total Pro-Forma Operating Revenue			÷	2,459,233 \$	5,282,911 \$	176,520 \$	6,440,820 \$	674,830 \$	35,806,523

LOUISVILLE GAS AND ELECTRIC COMPANY	Cost of Service Study	Class Allocation
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Description	Ref Name	Allocation Vector		Total System	Residential Rate R	Water Heating Rate WH	General Service Rate GS	Rate LC Primary	Rate LC Secondary
Cost of Service Summary Pro-Forma									
Operating Expenses									
Onarotiva and Maintenance Evaneae			e	508 149 420 \$	199 109 198 \$	1.147.550 \$	62.867.909 \$	5.837.225 \$	85,752,023
Operation and Amortization Evances			,					889,962	15,457,337
bepreviation and Amountance Experieds Acception Expanse				467 519	175,933	575	60.638	5.224	89,036
Pronents and Other Tayes		NPT		12 603 252	5.488.447	40.188	1.657.920	119,074	2,064,448
Amontization of Investment Tax Credit				(4.010.380)	(1,746,435)	(12,788)	(527,553)	(37,890)	(656,912)
Cithar Évnenses				(6.055.342)	(2.636.972)	(19,309)	(796,562)	(57,210)	(991,882)
State and Federal Income Taxes		TXINCPF		27,184,243 \$	2,736,402 \$	(270,924) \$	7,098,638 \$	483,843 \$	6,667,019
Specific Assignment of Interruptible Credit				(3,519,894)	•	,	ı	•	•
Allocation of interruptible Credits		SCP		3,519,694 \$	1,511,175 \$	2,563 \$	514,921 \$	41,545 \$	625,034
Adjustments to Operating Expenses:									
Eliminate mismatch in fuel cost recovery		Energy		(2,005,300) \$	(673,190) \$	(3,045) \$	(233,620) \$	(26,547) \$	(360,271)
Remove ECR expenses		ECREV		(1,766,344) \$	(670,920) \$	(2,417) \$	(256,487) \$	_	(305,205)
Eliminate brokered sales expenses		Energy		(25,030,766) \$	(8,402,958) \$	(38,013) \$	(2,916,114) \$		(4,497,006)
Eliminate DSM Expenses		DSMREV		(3,280,013) \$	(2,773,781) \$	₩7 ,	(109,057) \$	(25,643) \$	(340,540)
Year end Expense adjustment		YREND		1,458,544 \$	687,488 \$	(5,575) \$	(155,950) \$.	520,439
Adjustment to annualize depreciation expense		DET		8,959,741 \$	3,944,776 \$	30,089 \$	1,178,972 \$	83,210 \$	1,445,233
Deprectation adjustment		DET					20 1 0 0 1 1 0 0 1 0 0 1 0 0 1 0 0 1 0 0 1 0 0 1 0 0 1 0 0 1 0 0 1 0 0 10 0 10 0 10 0 10 0 10 0 10 0 10 0 10 1		
Labor adjustment	:	[8]		918,550 \$	¢ 200'524	\$ \$/N'5	¢ noc'szt	P +0.'0	PC1 (214-1
Adjustment for pension and post Ret EXp. (See Functional Assignment)	ignment)			70 400 ¢	46 703 6	AQA A	0,401 €	783 \$	5 995
biom damage adjustment Adjustment to eliminate advaction expense (Gee Functional Assimment)	beignment)	SUALL						*	2225
Aujustitettion of rate case expenses. Case i unionorial of the case expenses.	(Han Handler	OMT		333 580 \$	130.707 \$	753 \$	41.270 \$		56,293
Amortization of ESM audit expenses		R01		58,333 \$	22,362 \$	76 \$	8,475 \$	667 \$	10,071
Remove one-utility cost (See Functional Assignment)									
Adjustment for injuries and damages (See Functional Assignment)	ent)								
Adjustment for VDT net savings to shareholders		LBT		5,640,000 \$	2,597,500 \$	18,874 \$	758,646 \$	53,623 \$	860,403
Adjustment for merger savings		LBT		19,427,401 \$	8,947,281 \$	65,011 \$	2,613,213 \$	184,709 \$	2,963,722
Adjustment for merger amortization expenses		LBT		(2,722,005) \$	(1,253,618) \$	(9,109) \$	(366,142) \$	(25,880) \$	(415,252)
MISO Schedule 10 one time credit		PLTRT		209,577 \$	269,909 \$	882 \$	93,029 \$	8,014 8	080,001
Adjustment cumulative effect of accounting change		DET		5,280,909 \$	2,325,068 \$	1/./35 \$	584,891 5		070'100
Adjustment for IT staff reduction				(431,834) \$	(198,881) \$	\$ (1,445) \$	(1/80/96)	(4, 100) \$	(0/0'00)
Remove Alstom Expenses		PLPPT		(2,15/,640) \$	(620,723) 5 (FOD 2F2) 5	\$ (1997) \$ (1997)	(797,677)	(24,308) \$	(1007'01 0)
Adjustment for Obsolete inventory write-off				(1,3/3,532) \$	e (200'8AC)	6 (noc'+)			774 356
Adjustment for corporate office lease				6 (770R/1	0707'070 \$ /475 507' \$	0,010 8	241,303 U	(18 755) \$	(354 525)
		Energy Di DDT				(2,1,22) 4 A AER &	470 405 6		FON FOR
Adjustment for Cane Run repair ferund				2 (312 VCC)	(87.676) S	5 (38C)	30 52U S	(2 549) \$	(38.480)
VIDI Purcultzation and outdeon. Total Evoance Adhictments		10100		7 834 614	5.631.305	78.561	1,477,307	(42,506)	1,038,780
Total Operating Expenses	TOE		ŝ	641,996,290 \$	252,459,995 \$	1,288,231 \$	84,962,789 \$	7,239,267 \$	110,044,884
Net Operating Income Pro-Forma			5	67,635,652 \$	15,053,897 \$	(350,102) \$	14,470,463 \$	998,169 \$	14,581,963
Net Cost Rate Base			÷	1,473,843,556 \$	644,527,736 \$	4,772,258 \$	193,447,680 \$	13,870,109 \$	239,280,834
				1 500/	10100	WAR 7	7 494	1 00%	7460 8
				V cc't	5 1017			at an - i	

Exhibit (SJB-11) Page 4 of 6

LOUISVILLE GAS AND ELECTRIC COMPANY	Cost of Service Study	Class Allocation
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Description	Name	Allocation Vector		Rate LC-TOD Primary	Rate LC-TOD Secondary	Rate LP Primary	Rate LP Secondary	Rate LP-TOD Transmission	Rate LP-TOD Primary
Cost of Service Summary ~ Pro-Forma									
Operating Expenses									
Constitute and Majoritations Constants			ł						
			A	8,5/2,410 \$	12,627,670 \$	4,384,582 \$	21,563,584 \$	12,583,514 \$	58,100,988
				1,397,760	2,246,528	726,267	3,475,583	1,472,921	8,341,436
		!		8.260	13,315	4,274	19,713	9,676	50,318
Property and Uther Laxes		NPT		187,137	300,872	97,197	463,522	199,323	1,119,022
Amortization of Investment Tax Credit				(59,547)	(95,738)	(30,928)	(147,494)	(63,425)	(356,075)
Other Expenses				(89,912)	(144,556)	(46,699)	(222,703)	(95,766)	(537,644)
State and Federal Income Taxes		TXINCPF	5	803,548 \$	874,819 \$	175,256 \$	2,225,338 \$	895,341 \$	2,419,630
Specific Assignment of Interruptible Credit				1		ı	ı	(1,637,062)	(1,396,833)
Allocation of Interruptible Credits		SCP	ŝ	66,076 \$	84,505 \$	29,945 \$	140,138 \$	60.511 \$	270,035
Adjustments to Operating Expenses:									
Eliminate mismatch in fuel cost recovery		Enerov		(44.786) \$	(54.061) \$	(19.122) \$	\$ (96.898)	(63 230) \$	(273 643)
Remove ECR expenses		ECREV	- 59	(32,690) \$	(43.382) \$	(14.011) \$	(79 468) \$		(177 854)
Eliminate brokered sales expenses		Energy	- 43	(559,033) \$	(674,807) \$	(238,687) \$	(1,209,515) \$	(789.257) \$	(3.415.692)
Eliminate DSM Expenses		DSMREV	*7	(14,699) \$	(16,293) \$	· •>			
Year end Expense adjustment		YREND	\$9	•••	315,814 \$, ,	82,513 \$	ыл 1	•
Adjustment to annualize depreciation expense		DET	ŝ	130,688 \$	210,056 \$	67,905 \$	324,961 \$	137,715 \$	606'622
Depreciation adjustment		DET	69	, ,		\$.	،	•
Labor adjustment		LBT	6 9	13,628 \$	19,965 \$	6,919 \$	32,586 \$	15,832 \$	81,548
Adjustment for pension and post Ret Exp. (See Functional Assignment)	ent)								
Storm damage adjustment Adjustment to eliminate adjustion evenes (See Financial Antion		SDALL	ю	454 \$	719 \$	221 \$	1,509 \$	••• •	2,235
Aujusurient to eiminate advertising expense (See Functional Assignment) Amortiantion of rote acce accounts	ment	THC.	•		• • • • •				
Amortization of ESM andit expenses			₩	0,284 W	6,29U \$	2,8/8 \$	14,756 45	8,261 \$	38,141
Remove one-utility cost (See Functional Assimment)			7		e 014'1	+ - D+	-	¢ 701'1	RC/'C
Adjustment for injuries and damages (See Functional Assignment)									
Adjustment for VDT net savings to shareholders		LBT	v i	83.678 \$	122 585 \$	42 4R4 \$	200.077	97 7DA 🛠	500 ROD
Adjustment for merger savings		181	69	288,234 \$	477 252 \$	146.341 \$	689 180 \$	334830 \$	1 724 695
Adjustment for merger amortization expenses		LBT	\$	(40,385) \$	(59, 162) \$	(20,504) \$	(96,562) \$	(46.915) \$	(241.650)
MISO Schedule 10 one time credit		PLTRT	ø	12,672 \$	20,427 \$	6,557 \$	30,243 \$	14,845 \$	77,196
Adjustment cumulative effect of accounting change		DET	\$	77,028 \$	123,808 \$	40,023 \$	191,533 \$	B1,170 \$	459,682
Adjustment for IT staff reduction		LBT	\$	(6,407) \$	(9,386) \$	(3,253) \$	(15,319) \$	(7,443) \$	(38,337)
Remove Alstom Expenses		РГРРТ	63	(38,532) \$	(62,114) \$	(19,939) \$	(91,962) \$	(45,140) \$	(234,734)
Adjustment for Obsolete inventory write-off		PLT	6 7	(20,340) \$	(32,701) \$	(10,565) \$	(50,411) \$	(21,629) \$	(121,591)
Adjustment for corporate office lease		LBT	••	26,682 \$	39,088 \$	13,547 \$	63,798 \$	30,996 \$	159,657
Adjustment for carbide lime write-off		Energy	••	(31,641) \$	(38,193) \$	(13,509) \$	(68,457) \$	(44,671) \$	(193,324)
Agjustment for Cane Kun repair retund		P[PP]	1 9 (64,077 5	103,292 \$	33,156 \$	152,927 \$	75,064 \$	390,346
		VUIREV	-	(4,116) \$	(5.40/J. \$	(1,762) \$	(9.874) \$	(4,381) \$	(21.640)
I otal Expense Adjustments				(88,125)	392,206	19,142	67,620	(260,769)	(498,618)
Total Operating Expenses	TOE		÷	11,797,606 \$	16,299,721 \$	5,359,037 \$	27,585,302 \$	13,164,265 \$	67,512,261
Net Operating Income – Pro-Forma			ъ	1.636.974 \$	1.971.975 \$	467 201 \$	4 426 470 S	1 806 012 \$	6.014.729
Net Cost Rate Base			÷	21,825,190 \$	34,821,982 \$	11,284,222 \$	53,987,843 \$	23,320,016 \$	130,427,115
Rate of Return			-	7803 2	2 6612	74747	7806 8	7 740/	1.644
				la vu	W 00'7	N + 1 * N	0.4777	1.(478)	4.01%

12 CP Prod Trans Allocation All Other KUUC Corrections Included

Exhibit (SJB-11) Page 5 of 6

LOUISVILLE GAS AND ELECTRIC COMPANY	Class Allocation
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Class Allocation

12 Months Ended September 30, 2003

Description Ref Nar	Name V	Allocation Vector		Rate LP-TOD Secondary	Street Lighting Rate PSL	Street Lighting Rate SLE	Street Lighting Rate OL	Street Lighting Rate TLE	Special Contracts
Cost of Service Summary – Pro-Forma									
Operating Expenses									
Operation and Maintenance Expenses				1 RR5 521 S	2 594 748	1 70 A77 S	0 010 070 ¢	437 A76	76 867 866
Depreciation and Amortization Expenses			•			11 687		FO 201	2 721 670
Accretion Expense				1.442	523	45	575	329	27.674
Property and Other Taxes	z	NPT		35,890	138 773	1512	182 151	8.017	400 758
Amortization of Investment Tax Credit				(11.420)	(44,158)	(481)	(57.961)	(2.551)	(159 (124)
Other Expenses				(17,243)	(66,675)	(726)	(87.516)	(3.852)	(240,113)
State and Federal Income Taxes	F	TXINCPF	ы	167,645 \$	433,110 \$	14,364 \$	558,681 \$	62,883 \$	1.838.648
Specific Assignment of Interruptible Credit				. •	•		. 1	1	(486 000)
Allocation of Interruptible Credits	S	SCP	\$	12,085 \$	ب	5 9	ыў ,	1,678 \$	159,682
Adjustments to Operating Expenses:									
Eliminate mismatch in fuel cost recovery	ш	Energy	•7	(7,490) \$	(8,992) \$	(698) \$	(9.342) \$	(2.007) \$	(128.357)
Remove ECR expenses	ш	ECREV	5	(6,339) \$	(15,470) \$	(474) \$	(19,117) \$	(1,746) \$	(85,491)
Eliminate brokered sales expenses	ш	Energy	••	(93,494) \$	(112,246) \$	(8,719) \$	(116,606) \$	(25,054) \$	(1,602,194)
Eliminate DSM Expenses	0	DSMREV	\$	د י	• ,	u 7	• •	به ۱	•
Year end Expense adjustment	~	YREND	\$	•• ,	1,673 \$	(647) \$	9,548 \$	3,240 \$	•
Adjustment to annualize depreciation expense		DET	\$	25,304 \$	106,365 \$	1,093 \$	139,856 \$	5,640 \$	347,969
Uepreciation adjustment	. م	DET	ю (67 1 1	\$	هه د ا	ہ ہو ا	•••	
Advicement for an of the second second second for the second for the second for the second second second second		ц р	¢.	Z,545 \$	4,3/6 \$	157 \$	4,959 \$	650 \$	36,862
Aujusunen lui perision and post Ket EXp. (See Functional Assignment) Storm damane adirietment	ú		6	4	107 6	4 1		5	002
Adjustment to eliminate advertising expense (See Functional Assignment)	0		•	A 40	401 4	e 0	# 2000	e 17	969
Amortization of rate case expenses	G	OMT	67	1 093 \$	1 703 \$		1 017 \$	284 \$	17 638
Amortization of ESM audit expenses	æ	R01	\$	202 \$	496 3	15 \$	612 \$	56 \$	2.837
Remove one-utility cost (See Functional Assignment)								•	
Adjustment for injuries and damages (See Functional Assignment)									
Adjustment for VDT net savings to shareholders		LBT	\$9	15,623 \$	26,868 \$	962 \$	30,450 \$	3,992 \$	226,328
Adjustment for merger savings	2	LBT	÷	53,815 \$	92,550 \$	3,315 \$	104,889 \$	13,751 \$	779,605
Adjustment for merger amortization expenses	-	LBT	ŝ	(7,540) \$	(12,967) \$	(465) \$	(14,696) \$	(1,927) \$	(109,232)
MISO Schedule 10 one time credit	a .	PLTRT	67)		803 \$	6 9	833 \$	505 \$	34,786
Adjustment cumulative effect of accounting change	<u> </u>	DET	6 7 (14,914 S	62,692 \$	644 \$	82,431 \$	3,324 \$	205,095
	נים	L8T 21 2007			(2,057) \$	(74) \$	(2,331) \$	(306) \$	(17,329)
	2 0	PLPP	**	(6,725) \$	(2,441) 5	S (503)	(2,532) \$	(1,537) \$	(105,774)
Adjustment for Cospilete Inventory while-off	- :		1 9 ((3,907) \$	(15,303) \$	(165) \$	(20,097) \$	(873) \$	(54,285)
Adjustment for corporate onnee rease	5.	ñ	A 6	4,982 \$	6,568 5	30/ 8	9'/10 \$	1.273 \$	72,169
Adjustment for Case Due mile wille-on Adjustment for Case Due model and	ū	nergy L no T	n 6	<pre>4 (787'C)</pre>	(p,353) &	(493) \$	(e'eou) \$	(1,418) \$	(90,682)
Aujusviterii tui vaite kuirtepairi teruru VDT Amontisation and Sumadit	ī >	VDTDEV	A 4	11,163 &	4,039 5		4,211 S	2,555 \$	1/5,894
Total Evanese Adjuntments	>		9	6 (00)	4 (000) 1	& (7C)	₹ 105.201	\$ (907)	(CO.UT)
i otal Expense Adjustments				(684)	132,975	(4,987)	196,308	225	(304,127)
Total Operating Expenses	ň		÷	2,123,871 \$	4,326,516 \$	150,840 \$	5,200,996 \$	559,676 \$	31,921,034
Net Operating Income – Pro-Forma			63	335,362 \$	956,395 \$	25,680 \$	1,239,824 \$	115,154 \$	3,885,489
Net Cost Rate Base			67	4,194,659 \$	16,723,512 \$	185,073 \$	21,932.886 \$	941,914 \$	58,300,526
Bata of Bahim				7 000/	2202	7400 C F	, e.m.	10.000	
				× cc' 1	N.7.1°C	12.00%	9/ co'0	N.52.21	9/00.0

12 CP Prod Trans Allocation All Other KUUC Corrections Included

Exhibit (SJB-11) Page 6 of 6

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

IN THE MATTER OF:

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

EXHIBIT (SJB-12)

KENTUCKY UTILITIES Cost of Service Study Class Allocation

12 Months Ended September 30, 2003

Description		Total Svstem	Residential Rate RS	Ail Electric Residential Rate FERS	General Service GS	ce	Combined Light & Power LP.HLF.M	TOD I	Large Comm/Ind TOD Primary LCI-TOD
Cost of Service Summary – Pro-Forma									
Total Pro-Forma Operating Revenue	ø	693,449,939 \$	124,345,569	\$ 135,772,513	\$ 67,310,253	,253 \$	232,654,411	•7	85,699,043
Total Operating Expenses	ŝ	633,180,928 \$	121,678,365	\$ 133,986,084	\$ 58,484,592	,592 \$	201,628,996	**	75,886,497
Net Operating Income (Adjusted)	67	60,269,011 \$	2,667,204	\$ 1,786,429	\$ 8,825,661	,661 \$	31,025,414	\$	9,812,546
Net Cost Rate Base	θ	1,412,033,543 \$	318.616,683	\$ 371,840,037	\$ 142,212,684	,684 \$	342,893,824	₽ ₩	120,860,788
Rate of Return	Н	4.27%	0.84%	0.48%		6.21%	9.05%		8.12%
Subsidy at Current Rates		(0)	(18,406,858)	(23,714,808)	4,639,847	,847	27,596,286		7,835,982
KU Proposed Increases Proposed Base Rate Increase Increase in Miscellaneous Charges Decrease in Rents		58,911,660 1,003,763 (556,373)	10,917,610 539,919 (28,757)	13,171,979 395,326 (21,055)	un c	,663,282 65,368 (152,518)	18,928,419 3,118 (344,931)		6,910,666 7 (784)
Incremental Income Taxes		(24,104,760) \$	(4.641,041)	\$ (5.500,915)	\$ (2,264	(2,264,378) \$	(7,547,723)	69	(2,805,995)
Net Operating Income after increase		95,523,300 \$	9,454,934	\$ 9.831,763	\$ 12,137,415	,415 \$	42,064,297	\$7	13,916,440
Rate of Return at KU Proposed Rates	\vdash	6.76%	2:97%	2.64%		8.53%	12.27%		11.51%
Subsidy at KU Proposed Rates Change in Subsidy resulting from KU Proposed Rates		(0)	(20,372,091) 10.7%	(25,799,966) 8.8%	4,23	7,644 -8.7%	31,768,325 15.1%		9,865,126 23.3%
Base Rate Increase Required for Equalized Rates of Return		58,911,660	31,289,701	38,971,945	1,425,638	,638	(12,839,906)		(2,754,460)
Base Rate increase Required for 25% Subsidy Reduction Incremental Income Taxes		58,911,660 (24,104,760)	17,484,557 (7,307,774)	21,185,839 (8,755,215)	4,905,523 (1,956,664)	523 664)	7,857,308 (3,051,922)		3,122,526 (1,267,692)
Net Operating Income after increase		95,523,300 \$	13,355,149	\$ 14,591,323	\$ 11,687,370	370 \$	35,488,987	\$	11,666,603
Rate of Return after 25% Subsidy Reduction	Н	6.76%	4.19%	3.92%		8.22%	10.35%		3.65%
Subsidy after 25% Subsidy Reduction Change in Subsidy resulting from 25% Subsidy Reduction		(0)	(13,805,144) -25.0%	(17,786,106) -25.0%	3,479,885 -25.0%	79,885 -25.0%	20,697,214 -25.0%		5,876,987 -25.0%
Adjusted Revenue at Current Rates		676,762,013	121,233,915	131,265,061	65,598,531	,531	226,957,350	w)	84,135,770
Percentage Increase proposed by KU Percentage Increase to achieve equalized Rates of Return Percentage Increase to achieve 25% subsidy reduction		8.70% 8.70% 8.70%	9.01% 25.81% 14.42%	10.03% 29.69% 16.14%		8.63% 2.17% 7.48%	8.34% -5.66% 3.46%		8.21% -3.27% 3.71%

BJP Prod Trans Allocation Corrected Demand Allocation Removes ECR Rate Base Present Revenues Reflect CSR Incr Allocates CSR Credits on SCP

Exhibit (SJB-12) Page 1 of 3 KENTUCKY UTILITTES Cost of Service Study Class Allocation

12 Months Ended September 30, 2003

						Large Power Mine					
Description	Coa	Coal Mining Power Primary MPP	Coal Mining Power Transmission MPT		Large Power Mine Power TOD Primary LMPP	Power TOD Transmission LMPT	Combination Off Peak CWH		All Elcetric School AES	Electr Heati	Electric Space Heating Rider 33
Cost of Service Summary Pro-Forma											
Total Pro-Forma Operating Revenue	ю	4,900,693	с 3,6	3,840,839 \$	1,984,106	\$ 4,207,348	\$ 427,775	5 \$	4,051,813	÷	684,657
Total Operating Expenses	ŝ	3,986,444	\$ 3,2(3,209,576 \$	1,699,608	\$ 3,553,714	\$ 1,057,389	\$ 65	3,676,265		655,878
Net Operating Income (Adjusted)	69	914,249	й s	631,263 \$	284,498	\$ 653,634	\$ (629,614)	(4) \$	375,547	€9	28,779
Net Cost Rate Base	s	6,738,314	\$ 5,15	5,192,612 \$	2,812,219	\$ 6,367,053	\$ 4,518,731	ज्य १	8,113,397	5	1,490,422
Rate of Return	Ц	13.57%		12.16%	10.12%	10.27%	-13.93%	3%	4.63%		1.53%
Subsidy at Current Rates		1,055,102	99	689,710	276,917	642,975	(1,384,849)	(6)	49,246		(58,654)
KU Proposed Increases Proposed Base Rate Increase Increase in Miscellaneous Charges Decrease in Rents		405,257 9 (3,712)	'n	319,850 6 (2,603)	165,746 1 (356)	347,607 3 (1,166)	96,148 - -	<u>s</u> q			129,034
Incremental Income Taxes	s	(163,065)	\$ (1)	(128,831) \$	(67,163)	(140,685)	(39,044)	14) \$		63	(52,399)
Net Operating Income after increase	\$	1,152,739	φ γ	819.685 \$	382,726	\$ 859,393	\$ (572,510)	\$ (0	375,547	ия	105,414
Rate of Return at KU Proposed Rates	Н	17.11%		15.79%	13.61%	13.50%	-12.67%	1%	4.63%		7.07%
Subsidy at KU Proposed Rates Change in Subsidy resulting from KU Proposed Rates		1,173.390 11.2%	ν.	788,676 14.3%	324,088 17.0%	721,761 12.3%	(1,478.659) 6.8%	6	(291,825) -692.6%		7,725 -113.2%
Base Rate Increase Required for Equalized Rates of Return		(768,133)	(46	(468,826)	(158,342)	(374,154)	1,574,807	20	291,825		121,309
Base Rate increase Required for 25% Subsidy Reduction Incremental income Taxes		23,193 (7,914)		48.456 (18,623)	49,345 (19,894)	108,077 (43,416)	536,171 (217,730)	۲ĝ	328,759 (133,504)		77,318 (31,398)
Net Operating Income after increase	69	925,825	ę.	658,500 \$	313,594	\$ 717,133	\$ (311,173)	3) \$	570,803	\$	74,699
Rate of Return after 25% Subsidy Reduction	Ц	13.74%		12.68%	11.15%	11.26%	-6.89%	76	7.04%		5.01%
Subsidy after 25% Subsidy Reduction Change in Subsidy resulting from 25% Subsidy Reduction		791,326 -25.0%	ίο	517,283 -25.0%	207,688 -25.0%	482,231 -25.0%	(1,038,637) -25.0%	(2%)	36,934 -25.0%		(43,991) -25.0%
Adjusted Revenue at Current Rates		4,793,968	3,74	3,748,239	1,944,714	4,098,693	414,203	13	3,955,546		668,128
Percentage increase proposed by KU Percentage increase to achieve equalized Rates of Return Percentage increase to achieve 25% subsidy reduction		8.45% -16.02% 0.48%	Ţ	8.53% -12.51% 1.29%	8.52% -8.14% 2.54%	8.48% -9.13% 2.64%	23.21% 380.20% 129.45%	* * *	0.00% 7.38% 8.31%		19.31% 18.16% 11.57%

BJP Prod Trans Allocation Corrected Demand Allocations Removes ECR Rate Base Present Revenues Reflect CSR Incr Allocates CSR Credits on SCP

Exhibit (SJB-12) Page 2 of 3

KENTUCKY UTILITIES Cost of Service Study Class Allocation

12 Months Ended September 30, 2003

	<i>ū</i> .	Street 1 inhtinn	Decc	Decorative Street Private Outdoor Lichting	Private	rate Outdoor Lichting	Cus Outdoo	Customer Outdoor Linhting		Snerial
Description		StLt		Dec St Lt		POL	U	COLL		Contracts
Cost of Service Summary – Pro-Forma										
Total Pro-Forma Operating Revenue	÷	5,421,077	69	807,012	69	6,328,527	ø	898,820	ø	14,115,482
Total Operating Expenses	ŝ	5,595,768	s	685,056	\$	4,880,294	\$	722,198	ŝ	11,794,204
Net Operating Income (Adjusted)	\$	(174,691)	\$	121,956	\$	1,448,234	••	176,622	*	2,321,278
Net Cost Rate Base	**	31,905,511	ŝ	3,716,038	\$	15,836,075	\$	2,518,660	••	26,400,496
Rate of Refurm	Η	-0.55%		3.28%		9.15%		7.01%		8.79%
Subsidy at Current Rates		(2,587,059)		(61,715)		1,300,372		116,380		2,011,128
KU Proposed Increases Proposed Base Rate Increase Increase in Miscellaneous Charges Decrease in Rents		512,748 3 (219)		76,631 , (17)		517,636 3 (220)		72,319 - (36)		676,728
Incremental Income Taxes	69	(208,131)	ŝ	(31,112)	69	(210,116)	67	(29,353)	ŝ	(274,808)
Net Operating Income after increase	64	129,710	ŝ	167,459	69	1,755,537	69	219,552	÷	2,723,198
Rate of Return at KU Proposed Rates	Н	0.41%		4.51%		11.09%		8.72%		10.31%
Subsidy at KU Proposed Rates Change in Subsidy resulting from KU Proposed Rates		(3, 4 15,770) 32.0%		(141,315) 129.0%		1,152,074 -11.4%		82,784 -28.9%		1,578,032 -21.5%
Base Rate Increase Required for Equalized Rates of Return		3,928,518		217,946		(634,438)		(10,465)		(901,304)
Base Rate increase Required for 25% Subsidy Reduction Incremental Income Taxes		1,988,224 (807,298)		171,660 (69,702)		340,841 (138,322)		76,820 (31,181)		607,042 (246,510)
Net Operating Income after increase	69	1,006,019	ŝ	223,698	\$	1,650,535	\$	222,226	\$	2,681,810
Rate of Return after 25% Subsidy Reduction	Н	3.15%	\square	6.03%		10.42%		8.82%	Ш	10.16%
Subsidy after 25% Subsidy Reduction Change in Subsidy resulting from 25% Subsidy Reduction		(1,940,294) -25.0%		(46,286) -25.0%		975,279 -25.0%		87,285 -25.0%		1,508,346 -25.0%
Adjusted Revenue at Current Rates		5,402,425		807,559	-	6,293,269		893,164		14,551,478
Percentage Increase proposed by KU Percentage Increase to achieve equalized Rates of Return Percentage Increase to achieve 25% subsidy reduction		9.49% 72.72% 36.80%		9.49% 26.99% 21.26%		8.23% -10.08% 5.42%		8.10% -1.17% 8.60%		4.65% -6.19% 4.17%

BIP Prod Trans Allocation Corrected Demand Allocators Removes ECR Rule Base Present Revenues Reflect CSR Incr Allocates CSR Credits on SCP

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

IN THE MATTER OF:

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

EXHIBIT (SJB-13)

LOUISVILLE GAS AND ELECTRIC COMPANY Cost of Service Study Class Albocation

12 Months Ended September 30, 2003

Description		Total System	Residential Rate R	Water Heating Rate WH	General Service Rate GS	Rate LC/LC-TOD	Rate LP/LP-TOD	Street Lighting Rate PSL	Street Lighting Rate SLE
Cost of Service Summary – Pro-Forma									
Total Pro-Forma Operating Revenue	÷	709,631,942 \$	269,278,378 \$	952,526 \$	98,312,757 \$	163,343,827 \$	128,897,802 \$	5.453,014 \$	189,714
Total Operating Expenses	\$	641,996,290 \$	257,792,040 \$	1.325,576 \$	81,888.738 \$	141,780,579 \$	115,774,394 \$	4.801,103 \$	187,590
Net Operating Income (Adjusted)	\$	67,635,652 \$	11,486,338 \$	(373,051) \$	16,424,019 \$	21,563,248 \$	13,123,408 \$	651,910 \$	2,124
Net Cost Rate Base	÷	1,473,843,556 \$	680,151,878 \$	5,062,926 \$	170,825,435 \$	285,031,005 \$	225,299,290 \$	20,157,813 \$	451,450
Rate of Return	Н	4.69%	1.69%	-7.37%	9.61%	7-21	5.82%	3.23%	0.47%
Subsidy at Current Rates	ŝ	0	(33,300,831)	(1,021,989)	14,492,269	14,320,517	4,700,261	(461,109)	(31,389)
LG&E Proposed Increases Proposed Base Rate Increase Increase in Miscellaneous Charges		64,260,364 410,061	26,277,410 305,284	156,77 4	8,974,815 104,713	13,708,637 36	10,638,506 28	586,307 -	17,030 -
Incremental income Taxes		(26,361,864) \$	(10,836,010) \$	(63,906) \$	(3.701.124) \$	(5,588,121) \$	(4,336,628) \$	(238.999) \$	(6,942)
Net Operating Income after increase		105,944,212 \$	27,233,022 \$	(280,183) \$	21,802,423 \$	29,683,800 \$	19,425,313 \$	999,219 \$	12,212
Rate of Return at LG&E Proposed Rates	Н	7.19%	4.00%	-5.53%	12.76%	10.41%	8.62%	4.96%	2.70%
Subsidy at LG&E Proposed Rates Change in Subsidy resulting from LG&E Proposed Rates		(0)	(36,562,357) 9.8%	(1,087,370) 6.4%	16,076,190 10.9%	15,522,384 8.4%	5,452,942 16.0%	(759.301) 64.7%	(34,168) 8.9%
Base Rate Increase Required for Equalized Rates of Return		64,260,364	62,839,767	1,244,144	(7, 101, 375)	(1,813,747)	5,185,564	1,345,608	51,198
Base Rate increase Required for 25% Subsidy Reduction Incremental Income Taxes		64,260.364 (26,361,864)	37,864,144 (15,559,156)	477,652 (194,707)	3,767,827 (1,578,579)	8,926,641 (3,638,817)	8,710,760 (3,550,813)	999,777 (407,543)	27,656 (11,274)
Net Operating Income after increase		105,944,212 \$	34,096,609 \$	(90.106) \$	18,717,981 \$	26,851,108 \$	18,283,382 \$	1 244 144 \$	18,506
Rate of Return after 25% Subsidy Reduction	Η	7.19%	5.01%	-1.78%	10.96%	9.42%	8.12%	6.17%	4.10%
Subsidy after 25% Subsidy Reduction Change in Subsidy resulting from 25% Subsidy Reduction		o	(24,975,623) -25.0%	(766,492) -25.0%	10,869,202 -25.0%	10,740,388 -25.0%	3,525,196 -25.0%	(345,831) -25.0%	(23,542) -25.0%
Adjusted Revenue at Current Rates		561,367,938	213,814,897	722,586	81,284,688	128,727,508	98,118,565	4,777,509	138,741
Percentage Increase proposed by LG&E Percentage Increase to achieve equalized Rales of Return Percentage Increase to achieve 25% subsidy reduction		11,45% 11,45% 11,45%	12.29% 29.39% 17.71%	21.70% 172.18% 66.10%	11.04% -8.74% 4.64%	10.65% -1.41% 6.93%	10.84% 5.28% 8.88%	12.27% 28.17% 20.93%	12_27% 36.90% 19.93%

BIP Prod Trans Allocation Removes ECR Rate Base Present Revenues reflect CSR incr CSR Credits allocated on SCP

Exhibit (SJB-13) Page 1 of 2

LOUISVILLE GAS AND ELECTRIC COMPANY Cost of Service Study Class Allocation

12 Months Ended September 30, 2003

Description	0	Street Lighting Rate OL	ŝ	Street Lighting Rate TLE		Special Contracts
Cost of Service Summary – Pro-Forma						
Total Pro-Forma Operating Revenue	\$	6,617,260	69	677,761	\$	35,908,904
Total Operating Expenses	ŝ	5,693,263	s	566,398	**	32,186,608
Net Operating Income (Adjusted)	\$	923,997	ŝ	111,362	\$	3,722,296
Net Cost Rate Base	*)	25,495,128	\$	1,001,089	\$	60,367,542
Rate of Return	Н	3.62%		11.12%		6.17%
Subsidy at Current Rates		(415,268)		110,441		1,607,097
LG&E Proposed Increases Proposed Base Rate Increase Increase in Miscellaneous Charges		726,051 -		56,796		3,118,038 -
Incremental income Taxes	\$	(295,963)	\$	(23,152)	\$	(1,271,018)
Net Operating Income after increase	47	1,354,085	\$	145,006	\$	5,569,315
Rate of Return at LG&E Proposed Rates	Н	5.31%		14.48%		9.23%
Subsidy at LG&E Proposed Rates Change in Subsidy resulting from LG&E Proposed Rates		(807,912) 94.6%		123,311 11.7%		2,076.282 29.2%
Base Rate Increase Required for Equalized Rates of Return		1,533,963		(66,515)		1,041,756
Base Rate increase Required for 25% Subsidy Reduction Incremental Income Taxes		1,222,512 (498,337)		16,316 (6,651)		2,247,079 (915,986)
Net Operating Income after increase	\$	1,648,172	\$	121,028	\$	5,053,389
Rate of Return after 25% Subsidy Reduction	Н	6.46%		12.09%		8.37%
Subsidy after 25% Subsidy Reduction Change in Subsidy resulting from 25% Subsidy Reduction		(3†1,451) -25.0%		82,831 -25.0%		1,205,322 -25.0%
Adjusted Revenue at Current Rates		5,908,023		543,908		27,331,513
Percentage Increase proposed by LG&E Percentage Increase to achieve equalized Rates of Return Percentage Increase to achieve 25% subsidy reduction		12.29% 25.96% 20.69%		10.44% -12.23% 3.00%		11.41% 3.81% 8.22%

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

IN THE MATTER OF:

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

EXHIBIT (SJB-14)

	(8)	Calculated Revenue Proposed @ Proposed Rates KIUC Rates	120.00 \$ 37,800 4.79 19,476,875 0.73 2,897,781 (4.19) (271,655) 21,553	\$ 0.02200 45,779,244	\$ 67,941,598 0.999029 \$ 68,007,665	1,698,726 (1,573,353) (192,241) 8,140 -	\$ 67,948,937	2,402,371 3.67%	\$ 68,220,592 2,466,557 3.75%
	(2)	Calculated Revenue @ Proposed Pro KU Rates R	37,800 \$ 22,456,486 \$ 2,897,781 \$ (271,655) \$ 21,553	45,779,244 \$ 0.0	70,921,209 0.999029 70,990,174	1,698,726 (1,573,353) (192,241) 8,140	70,931,445	5,384,879 8.22%	71,203,101 5,449,065 8.29%
	(9)	Proposed Rates	\$ 120.00 \$ \$ 5.52 \$ 0.73 \$ (4.19)	\$ 0.02200	မ ကြ		s		σ I
	(5)	Calculated Revenue @ Present Rates	(see Exhibit 9) \$ 16,842,364 \$ 2,897,781 \$ (207,469) 21,553	45,987,332	6 65,541,561 0.999029 6 65,605,294	1,698,726 (1,573,353) (192,241) 8,140	65,546,566		65,754,035
	(4)	Present Rates	\$ 4.14 % \$ 0.73 %	\$ 0.02210	မ မျ		6		S.
EASE TEMBER 30, 2003	(3)	Total KWH		2,080,874,735					ble Credit) Credit)
PANY LECTRIC RATE INCR ONTHS ENDED SEP	(2)	Bills / KW	315 4,068,204 3,969,563 64,834		se Rates Correction Factor I of Correction Factor	ia for rollin t Adjustment nd Customers		Ş	without Interruptil out Interruptible (se
KENTUCKY UTILITIES COMPANY CALCULATION OF PROPOSED ELECTRIC RATE INCREASE BASED ON SALES FOR THE 12 MONTHS ENDED SEPTEMBI	(1)		LCIP - Rate Code 563 Number of Customers On-Peak Demand Off-Peak Demand CSR Credits Penalties	Energy	Total Calculated at Base Rates Correction Factor Total After Application of Correction Factor	Fuel Clause Billings - proforma for rollin Merger Surcredit Value Delivery Surcredit VDT Amortization & Surcredit Adjustment Adjustment to Reflect Year-End Customers	Total Rate LCI Primary	Proposed Increase Percentage Increase	Total Rate LCI Primary (without Interruptible Credit) Proposed Increase (without Interruptible Credit) Percentage Increase

Exhibit ____ (SJB-14) Page 1 of 2

KENTUCKY UTILITIES COMPANY CALCULATION OF PROPOSED ELECTRIC RATE INCREASE BASED ON SALES FOR THE 12 MONTHS ENDED SEPTEMBER 30, 2003	KIC RATE INCREAS	5E 1BER 30, 2003						
(1)	(2)	(3)	(4)	(5)	(9)	(2)	(9)	(2)
I	Bills / KW	Total KWH	Present Rates	Calculated Revenue @ Present Rates	Proposed Rates	Calculated Revenue @ Proposed KU Rates	Proposed Rates	Calculated Revenue @ Proposed KIUC Rates
LCIT - Rate Code 564 Number of Customers On-Peak Demand Off-Peak Demand CSR Credits Penalties	48 1,099,952 1,092,494 122,014		\$ 3.95 \$ 0.73 \$ (3.10)	(sec	69 33 30	\$ 5,760 5,862,744 797,521 (499,036) 76,807	0000	\$ 5,760 5,057,123 797,521 (499,036) 76,807
Energy		621,047,926	\$ 0.02210	13,725,159	\$ 0.02200	13,663,054	\$ 0.02200	13,663,054
Total Calculated at Base Rates Correction Factor Total After Application of Correction Factor	Factor tion Factor		ଦ ଜ	18,566,054 0.999990 18,566,238	. I.II	\$ 19,906,850 0.999990 \$ 19,907,046	F11	\$ 19,101,229 0.999990 \$ 19,101,418
Fuel Clause Billings - proforma for rollin Merger Surcredit Value Delivery Surcredit VDT Amortization & Surcredit Adjustment Adjustment to Reflect Year-End Customers	rollin stment istomers			526,690 (450,942) (55,117) 2,334		526,690 (450,942) (55,117) 2,334		526,690 (450,942) (55,117) 2,334
Total Rate LCI Transmission			~	18,589,204	I	\$ 19,930,012	1	\$ 19,124,383
Proposed Increase Percentage Increase						1,340,808 7.21%		535,180 2.69%
Total Rate LCI Primary (without Interruptible Credit) Proposed Increase (without Interruptible Credit) Percentage Increase	ut Interruptible terruptible Cre	Credit) dit)	~	18,967,446		\$ 20,429,048 1,461,602 7.71%		\$ 19,623,420 655,974 3.46%
Total Rate LCI (without Interruptible Credit) Proposed Increase (without Interruptible Credit) Percentage Increase	uptible Credit) iterruptible Cre	dit)	∽.	84,721,482		\$ 91,632,149 6,910,667 8.16%	,	\$ 87,844,012 3,122,530 3.69%

Exhibit (SJB-14) Page 2 of 2

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

IN THE MATTER OF:

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

EXHIBIT (SJB-15)

Calculated Calculated Revenue Revenue at Proposed at Proposed Arbosed Arbosed Arbosed At Proposed At P	\$ 00.00 \$ - \$	- \$ 11.65 - 9.13	- \$ 0.02000	- \$ 11.65 - \$ 9.13	• •			
Proposed Rates	\$ 00.06 \$	\$ 12.01 \$ 9.49	\$ 0.02000	\$ 12.01 \$ 9.49	· ·			<u>a</u> l a
Calculated Revenue at Present Rates			ı				,	1
Present Rates	67 - 68	\$ 7.39 \$ 4.87	\$ 0.02480	\$ 7.39 \$ 4.87	•••••• ,			σ.
Billing Determinants	ı	kW-Months - -	kWhi's	kW-Months - -				
	INDUSTRIAL POWER RATE LP - TRANSMISSION VOLTAGE Customer Charges	Demand Charges Summer Season Winter Season	Energy Charges	Power Factor Provision Summer Season Winter Season	Subtotal @ base rates before application of correction factor Correction Factor - Subtotal @ base rates after application of correction factor	Fuei Adjustment Clause - proforma for rollin	Merger Surcredit Value Delivery Surcredit VDT Amortization & Surcredit Adjustment Adjustment to Reflect Year-End Customers	TOTAL INDUSTRIAL POWER RATE LP PRIMARY PROPOSED INCREASE Percentage Increase

Note: Currently no customers are served under this rate

Exhibit (SJB-15) Page 1 of 6

LOUISVILLE GAS AND ELECTRIC COMPANY CALCULATION OF PROPOSED ELECTRIC RATE INCREASE BASED ON SALES FOR THE 12 MONTHS ENDED SEPTEMBER 30, 2003

	Billing Determinants		Present Rates		Calculated Revenue at Present Rates	۹. E	Proposed Rates		Calculated Revenue at Proposed Rates	-	Proposed Rates	ا ھ چ	KIUC Cal	Calculated Revenue at Proposed KIUC Rates
INDUSTRIAL POWER RATE LP - PRIMARY VOLTAGE Customer Charges	494	÷	42.64	÷	21,064	ŝ	90.06	ŝ	44,460	\$	00.06	s, S		44,460
Demand Charges Summer Season Winter Season	ktw-Months_ 95,177 181,277 276,454	69 69	8.55 6.01		813,763 1,089,475	\$	13.17 10.63		1,253,481 1,926,975	69 69	12.81 10.27	31	22	1,218,979 1,861,261
Energy Charges	<u>kWm's</u> 111,622,714	ŝ	0.02480		2,768,243	69	0.02000		2,232,454	**	0.02000	8	2	2,232,454
Power Factor Provision Summer Season Winter Season	klW-Months (806) (3.501) (4.307)	የ የ	8.55 6.01		(6.891) (21,041)	69 69	13.17 10.63		(10.615) (37.216)	69 19	12.81 10.27	57		(10,323) (35,947)
Subtotal @ base rates before application of correction factor Correction Factor - Subtotal @ base rates after application of correction factor		0	0.999681	~ ~	4,664,613 4,666,103	Q	0.999681	~~~	5,409,539 5,411,266		0.999681		ດີ່ດີ	5,310,885 5,312,581
Fuel Adjustment Clause - proforma for rollin					(58,665)				(58,665)					(58,665)
Merger Surcredit Value Delivery Surcredit VDT Amortization & Surcredit Adjustment Adjustment to Reflect Year-End Customers	,				(130.757) (29.824) 349 -				(130,757) (29,824) 349 -				<u> </u>	(130,757) (29,824) 349 -
TOTAL INDUSTRIAL POWER RATE LP PRIMARY				••	4,447,206			-	5,192,370			5		5,093,684
PROPOSED INCREASE Percentage Increase								••	745,164 16.76%			••	•	646,478 14.54%

Exhibit (SJB-15) Page 2 of 6

LOUISVILLE GAS AND ELECTRIC COMPANY CALCULATION OF PROPOSED ELECTRIC RATE INCREASE BASED ON SALES FOR THE 12 MONTHS ENDED SEPTEMBER 30, 2003

	Billing Determinants		Present Rates		Calculated Revenue at Present Rates	Ŀ	Proposed Rates		Calculated Revenue at Proposed Rates	Ē	Proposed Rates	60	Calculated Revenue at Proposed KIUC Rates
INDUSTRIAL POWER RATE LP - SECONDARY VOLTAGE Customer Charges	4,225	\$	42.64	69	180,154	\$	00.06	**	380,250	69	00.06	63	380,250
Demand Charges Summer Season Winter Season	kW-Months 495 852 927,407 1,423,259	69 69	10.41 7.90		5.161,819 7,326,515	የ የ	14.27 11.73		7,075,808 10,878,484	69 69	13.91 11.37		6,896,060 10,542,296
Energy Charges	<u>kWh's</u> 553,836,275	••	0.02480		13,735,140	\$	0.02000	_	11,076,726	67	0.02000		11,076,726
Power Factor Provision Summer Season Winter Season	KW-Months (4.581) (10,121) (14,702)	69 69	10.41 7.90		(47,688) (79,956)	\$\$ \$P	14.27 11.73		(65.371) (118,719)	69 69	13.91 11.37		(63,710) (115,050)
Subtotal @ base rates before application of correction factor Correction Factor - Subtotal @ base rates after application of correction factor		0	0.999681	~ ~~	26,275,984 26,284,374	D	0.999681	w w	29,227,177 29,236,509	0	0.999681	~ ~	28,716,571 28,725,740
Fuel Adjustment Clause - proforma for rollin					(277,626)				(277,626)				(277.626)
Merger Surcredit Value Delivery Surcredit VDT Amortization & Surcredit Adlustment Adjustment to Reflect Vear-End Customers	3,146,798				(738.856) (167.175) 1.955 147.900				(738.856) (167.175) 1,955 165.294				(738.856) (167.175) 1,955 162,285
TOTAL INDUSTRIAL POWER RATE LP SECONDARY				•	25,250,571			**	28,220,101			~	27,706,322
PROPOSED INCREASE Percentage Increase								~	2,969,530 11.76%			••	2,455,752 9.73%

Exhibit ____ (SJB-15) Page 3 of 6

LOUISVILLE GAS AND ELECTRIC COMPANY CALCULATION OF PROPOSED ELECTRIC RATE INCREASE BASED ON SALES FOR THE 12 MONTHS ENDED SEPTEMBER 30, 2003	ASE EMBER 30, 2003												
	Blilling Determinants		Present Rates		Calculated Revenue at Present Rates	E.	Proposed Rates		Calculated Revenue at Proposed Rates	a.	Proposed Rates		Calculated Revenue at Proposed KIUC Rates
INDUSTRIAL POWER RATE LPTOD - TRANSMISSION VOLTAGE Customer Charges	73	Ś	44.62	⇔	3,257	÷	120.00	. ↔	8,760	\$	120.00		8,760
Basic Demand Charges	<u>kW-Months</u> 696,788	÷	2.05		1,428,415	\$	2.33		1,623,516	\$	2.23		1,556,006
Peak Demand Charges Summer Peak Winter Peak	kW-Months 234,813 454,878 689,691	აა	5.36 2.84		1,258,598 1,291,854	69 69	9.65 7.11		2,265,945 3,234,183	ርን ርን	9.38 6.84		2.203,576 3,113,360
Energy Charges	kWh's 376,359,726	\$	0.02480		9,333,721	\$	0.02000		7,527,195	\$	0.02000		7,527,195
Power Factor Provision Basic Demand Summer Peak Winter Peak	kW-Months (25,159) (7,762) (17,215)	69 69 69	2.05 5.36 2.84		(51,576) (41,604) (48,891)	69 69 69	2.33 9.65 7.11		(58,620) (74,903) (122,399)	69 69 69	2.23 9.38 6.84		(56,183) (72,842) (117,826)
Interruptible Service Rider	kW-Months 411,322	v)	(3.30)		(1,357,363)	ŝ	(3.98)		(1,637,062)	69	(3.98)	_	(1.637,062)
Subtotal @ base rates before application of correction factor Correction Factor - Subtotal @ base rates after application of correction factor		~	1.000343	~ ~	11,816,412 11,812,356	4	1.000343	vi vi	12,766,615 12,762,233	÷	1.000343	~ ~	12,524,984 12,520,685
Fuel Adjustment Clause - proforma for rollin					(213,291)				(213,291)				(213,291)
Merger Surcredit Value Delivery Surcredit VDT Amortization & Surcredit Adjustment Adjustment to Reflect Year-End Customers					(328,889) (74,173) 867				(328,889) (74,173) 867				(328,889) (74,173) 867
TOTAL INDUSTRIAL POWER RATE LPTOD TRANSMISSION				~	11,196,870			÷	12,146,747			~	11,905,199

13,542,260 988,028 7.87%

13.783,808 1,229,576 9.79%

12,554,232

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TOTAL INDUSTRIAL POWER RATE LPTOD TRANSMISSION (without Interruptible Credit) PROPOSED INCREASE (without Interruptible Credit) Percentage Increase

PROPOSED INCREASE Percentage Increase

708,329 6.33%

•••

949,877 8.48%

•

Exhibit (SJB-15) Page 4 of 6

Calculated Revenue Proposed at Proposed Rates KIUC Rates	\$ 120.00 \$ 64,800	\$ 3.42 10,144,612	\$ 9.36 9.351.277 \$ 6.84 13.365,885	\$ 0.02000 31,947,215	\$ 3.42 (355,671) \$ 9.38 (386,022) \$ 6.84 (398,556)	\$ (4.05) (1,396,833)	\$ 62,334,709 1.000342 \$ 62,313,393	(864,770)	(1,626,347) (366,371) 4,284	\$ 59,460,189	\$ 4,181,767 7.56%	\$ 60,857,022 \$ 4,440,440 7,87%
Calculated Revenue at Proposed Rates	\$ 64,800	10,431,745	9,615,955 13,884,586	31,947,215	(365,737) (399,004) (414,023)	(1,396,833)	63,368,703 63,347,034	(864,770)	(1.626,347) (366,371) 4,284	60,493,830	5,215,408 9.43%	61,890,663 5,474,081 9.70%
Proposed Rates	\$ 120.00	\$ 3.52	\$ 9.65 \$ 7.11	\$ 0.02000	\$ 3.52 \$65 7.11	\$ (4.05)	1.000342			∽ ∥	\$	୶
Calculated Revenue at Present Rates	24,095	9,483,405	5,341,090 5,546,023	39,614,547	(332,489) (221,623) (165,376)	(1,138,160)	58,151,511 58,131,626	(864,770)	(1,626,347) (366,371) 4,284	55,278,422		56,416,582
Present Rates	\$ 44.62 \$	\$ 3.20	\$ 5.36 2.84	\$ 0.02480	\$ 5.30 2.84 2.84	\$ (3.30)	1.000342 \$			-		₩.
Billing Determinants	540	<u>kW-Months</u> 2.963,564	KW-Months 996,472 1,952,825 2,949,297	kWh's 1.597,360,760	KWXMonths (103.903) (41.348) (58.231)	kW-Months 344,897						t Interruptible Credit)
	INDUSTRIAL POWER RATE LPTOD - PRIMARY VOLTAGE Customer Charges	Basic Demand Charges	Peak Dermand Charges Summer Peak Winter Peak	Energy Charges	Power Factor Provision Basic Demand Summer Peak Winter Peak	Interruptible Service Rider	Subtotal @ base rates before application of correction factor Correction Factor - Subtotal @ base rates after application of correction factor	Fuel Adjustment Clause - proforma for rollin	Merger Surcredit Vatue Delivery Surcredit VDT Amortization & Surcredit Adlustment Adlustment to Reflect Year-End Customers	TOTAL INDUSTRIAL POWER RATE LPTOD PRIMARY	PROPOSED INCREASE Percentage Increase	TOTAL INDUSTRIAL POWER RATE LPTOD PRIMARY (without Interruptible Credit) PROPOSED INCREASE (without Interruptible Credit) Percentage Increase

LOUISVILLE GAS AND ELECTRIC COMPANY CALCULATION OF PROPOSED ELECTRIC RATE INCREASE BASED ON SALES FOR THE 12 MONTHS ENDED SEPTEMBER 30, 2003

Exhibit (SJB-15) Page 5 of 6

LOUISVILLE GAS AND ELECTRIC COMPANY	
CALCULATION OF PROPOSED ELECTRIC RATE INCREASE	
BASED ON SALES FOR THE 12 MONTHS ENDED SEPTEMBER 30, 2003	
Calculated	culated

ulated Calculated venue Revenue posed Proposed at Proposed Rates Rutes KUC Rates	\$ 120.00 \$	531,143 \$ 4.52 520,004	306,166 \$ 9.38 297,738 569,283 \$ 6.84 548,016	218 \$ 0.02000 856.218	(9.014) \$ 4.52 (8.825) (5.143) \$ 9.38 (5.002) (9.982) \$ 6.84 (9.610)	791 \$ 2,216,661 1.000343 \$ 2,215,900 016 \$ \$ 2,215,900	(21,506) (21,506)	(12,520) (56,520) (56,520) (12,486) (12,486) (12,486) 146 146 - 14	<u> 50</u>	220,155 \$\$ 180,039 11.32% 9.25%	592 \$ 109,324,823 505 \$ 109,324,823
Calc Re at Pro	- v	531	306 569	856,218	ම ග් ම	\$ 2,256,791 \$ 2,256,016	(21,	(56. (12,	\$ 2,165,650	\$ 220, 11.	\$ 111,252,592 \$ 10,638,505
Proposed Rates	\$ 120.00	\$ 4.62	\$ 9.65 \$ 7.11	\$ 0.02000	\$ 4.62 \$ 9.65 \$ 7.11	1.000343					_
Calculated Revenue at Present Rates	6,738	587,476	170,057 227,393	1,061,711	(9.970) (2,857) (3,987)	2,036,561 2,035,862	(21,506)	(56,520) (12,486) 146 -	1,945,496		100,614,087
Present Rates	\$ 44.62 \$	\$ 5.11	\$ 5.36 2.84	\$ 0.02480	\$ 5.11 \$ 5.36 \$ 2.84	1.000343 \$			~		υ.
Billing Determinants	151	kW-Months 114,966	KW-Months 31,727 80,068 111,795	kWh's 42,810,915	kW-Months (1,951) (1,404) (1,404)						EDIT
	INDUSTRIAL POWER RATE LPTOD - SECONDARY VOLTAGE Customer Charges	Basic Demand Charges	Peak Demand Charges Summer Peak Winter Peak		Power Factor Provision Basic Demand Summer Peak Winter Peak	Subtotal @ base rates before application of correction factor Correction Factor - Subtotal @ base rates after application of correction factor	Fuel Adjustment Clause - proforma for rollin	Merger Surcredit Value Delivery Surcredit VDT Amortization & Surcredit Adjustment Adjustment to Reflect Year-End Customers	TOTAL INDUSTRIAL POWER RATE LPTOD SECONDARY	PROPOSED INCREASE Percentage Increase	TOTAL INDUSTRIAL POWER RATE LESS INTERRUPTIBLE CREDIT PROPOSED INCREASE

EXHIBIT (SJB-16)

ANALYSIS OF LGE/KU EXPECTED HOURLY OPERATION OF COMBUSTION TURBINES (Test year ending September 30, 2003 and Calendar year 2004)

Unit	MW	Test Year Hours	2004 Hours	<u>Average Hours'</u>	ΜŴ	Mw Wid Hrs ²	Heat Rate Mw Wtd HR ²	w Wtd HR ²
Cane Run 11	14	ŝ	0	ן. נז	0	0		
Brown 5	117	76	20	73	117	6.44	12,185	451
Brown 6	154	171	370	270.5	154	31.39	10,532	1,902
Brown 7	154	221	306	263.5	154	30.58	10,544	1,855
Brown 8	106	108	45	76.5	106	6.11	12,033	423
Brown 9	106	67	40	53.5	106	4.27	11,994	295
Brown 10	106	83	43	63	106	5.03	11,920	345
Brown 11	106	36	36	36	106	2.88	11,875	196
Heafling	36	0	0	0	0	0.00		
Paddys Run 11	12	0	0	0	0	0.00		
Paddys Run 12	23	0	0	0	0	0.00		
Paddys Run 13	158	293	87	190	158	22.62	9,919	1,291
Trimble County 5	160	375	207	291	160	35.09	10,624	2,144
Trimble County 6	160	310	178	244	160	29.42	10,645	1,802
Trimble County 7	155		148	148	0	00.00		
Trimble County 8	155		104	104	D	0.00		
Trimble County 9	155		0	0	0	00.00		
Trimble County 10	155		0	0	0	00.00		
Waterside 7	11	0	0	0	0	0.00		
Waterside 8	11	0	Ð	0	0	0.00		
Zorn 1	14	4	a	2	a	<u>0.00</u>		
Weighted Average	2068	1747	1634	1817	1327	174		10,704
¹ If unit was not shown as available in test year, average is set at 2004 hours	ailahle in test vear av	verane is set at 2004 hours	I					

¹ If unit was not shown as available in test year, average is set at 2004 hours. ² Weighted by "Mw weighted hours" for non-zero capacity factor units in both test year and 2004. ³ Weighted average hours of operation for non-zero capacity factor units in both test year and 2004. ⁴ Mw for units with non-zero capacity factors in both test year and 2004.

Exhibit_(SJB-16)

EXHIBIT (SJB-17)

Exhibit (SJB-17) Page 1 of 2

Kentucky Utilities Company

ELECTRIC RIDER

CSR Curtailable Service Rider (KIUC REVISED)

APPLICABLE

In all territory served.

AVAILABILITY OF SERVICE

This rider shall be made available to any customer served under the applicable power schedules who contracts for not less than 1,000 kilowatts of their total requirements to be subject to curtailment upon notification by the Company.

CONTRACT OPTION

1

Customer may, at Customer's option, contract with Company to curtail service upon notification by the Company. Requests for curtailment shall not exceed one, hundred seveny-five (175) hours per year nor shall any single request for curtailment be for less than thirty (30) minutes or for more than fourteen (14) hours per calendar day, with unlimited requests for curtailment per calendar day within these parameters. Company may request or cancel a curtailment at any time during an hour, but shall give no less than one hour notice when either requesting or canceling a curtailment.

Compliance with a request for curtailment shall be measured in one of the following two ways:

- a) The customer shall contract for a given amount of firm demand, and the curtailment load shall be the Customer's monthly billing demand in excess of the firm contract. During a request for curtailment, the customer shall reduce its demand to the firm demand designated in the contract. The difference in the maximum demand in the billing month and the maximum demand in any requested curtailment period, but not less than the contracted firm demand, in the billing period shall be the curtailable demand on which the monthly credit is based. The demand in excess of the firm load during each requested curtailment in the billing period shall be the measure of noncompliance.
- b) The customer shall contract for a given amount of curtailable load by which the customer shall agree to reduce its demand from the monthly maximum demand. During a request for curtailment, the Customer shall reduce its demand to a level equal to the maximum monthly demand less the curtailable load designated in the contract. The difference in the maximum demand in the billing month and the maximum demand in any requested curtailment period, but not more than the contracted curtailable load, in the billing period shall be the curtailable load and the actual curtailed load during each requested curtailment in the billing period shall be the measure of non-compliance.
- c) In those months in which the Company does not request load curtailment, the customer will receive a credit based on either the difference in the monthly billing demand and the contracted firm demand, a) above, or the contracted curtailable demand, b) above.

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Transmission

RATË

Customer will receive a credit against the applicable power schedule for curtailable kW, as determined in the preceding paragraph, times the applicable credit. Customers will be charged for the portion of each requested curtailment not met at the applicable charge.

	Primary	Transmission
Demand Credit of:	\$ 4.19 per KW	\$ 4.09 per KW
Non-Compliance Charge of	\$16.00 per KW	\$16.00 per KW

For each kWh of actual interrupted energy, customer will receive an additional credit equal to the avoided energy cost of the Company's average combustion turbine capacity less the applicable energy charge paid by the customer under customer's applicable firm tariff. The average cost of combustion turbine capacity will be determined by multiplying the nonthly average cost of natural gas per mobile used to supply its combustion turbine capacity times a heat rate of 10.704 btu's per kWh. Actual interrupted energy shall be determined by accumulating the kW of interrupted demand over the interruption period during any month.

Failure of Customer to curtail when requested to do so may result in termination of service under this rider.

BUY-THROUGH OPTION

Upon notification of a request for interruption, customer will be offered the option of purchasingenergy at the Company's avoided cost, based on prevailing market conditions, in lieu of being interrupted. The Company shall provide customer with the cost, in dollars per mWh, associated with such buy-through energy, based on the Company's best estimate at the time. In addition, the Company shall be permitted to charge customer a transaction fee of one-half (0.5) mill per kWh to cover the costs of obtaining the buy-through energy. This buy-through provision shall only apply in the event of a Company request for an economic interruption. It shall not be applicable in the event of a request to interrupt for reliability reasons, as determined by the Company's system operators.

TERM OF CONTRACT

The minimum original contract period shall be one year and thereafter until terminated by giving at least 6 months previous written notice, but Company may require that contract be executed for a longer initial term when deemed necessary by the size of the load or other conditions.

TERMS AND CONDITIONS

Except as specified above, all other provisions of the power rate to which this schedule is a rider shall apply

Formatted: Font: Bold Formatted: Font: Bold Formatted: Indent: Left: 0.5" EXHIBIT (SJB-18)

Louisville Gas and Electric Company

ELECTRIC RIDER

CSR Curtailable Service Rider (KIUC REVISED)

APPLICABLE

In all territory served.

AVAILABILITY OF SERVICE

This rider shall be made available to any customer served under the applicable power schedules who contracts for not less than 1,000 kilowatts of their total requirements to be subject to curtailment upon notification by the Company.

CONTRACT OPTION

١

Customer may, at Customer's option, contract with Company to curtail service upon notification by the Company. Requests for curtailment shall not exceed one, hundred sevent for (175) hours per year nor shall any single request for curtailment be for less than thirty (30) minutes or for more than fourteen (14) hours per calendar day, with unlimited requests for curtailment per calendar day within these parameters. Company may request or cancel a curtailment at any time during an hour, but shall give no less than one hour, notice when either requesting or canceling a curtailment.

Compliance with a request for curtailment shall be measured in one of the following two ways:

- a) The customer shall contract for a given amount of firm demand, and the curtailment load shall be the Customer's monthly billing demand in excess of the firm contract. During a request for curtailment, the customer shall reduce its demand to the firm demand designated in the contract. The difference in the maximum demand in the billing month and the maximum demand in any requested curtailment period, but not less than the contracted firm demand, in the billing period shall be the curtailable demand on which the monthly credit is based. The demand in excess of the firm load during each requested curtailment in the billing period shall be the measure of noncompliance.
- b) The customer shall contract for a given amount of curtailable load by which the customer shall agree to reduce its demand from the monthly maximum demand. During a request for curtailment, the Customer shall reduce its demand to a level equal to the maximum monthly demand less the curtailable load designated in the contract. The difference in the maximum demand in the billing month and the maximum demand in any requested curtailment period, but not more than the contracted curtailable load, in the billing period shall be the curtailable load and the actual curtailed load during each requested curtailment in the billing period shall be the measure of non-compliance.
- c) In those months in which the Company does not request load curtailment, the customer will receive a credit based on either the difference in the monthly billing demand and the contracted firm demand, a) above, or the contracted curtailable demand, b) above.

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RATE

Customer will receive a credit against the applicable power schedule for curtailable kW, as determined in the preceding paragraph, times the applicable credit. Customers will be charged for the portion of each requested curtailment not met at the applicable charge.

	Primary	Transmission
Demand Credit of:	\$ 4.05 per KW	\$ 3.98 per KW
Non-Compliance Charge of	\$16.00 per KW	\$16.00 per KW

For each kWh of actual interrupted energy, customer will receive an additional credit equal to the avoided energy cost of the Company's average combustion turbine capacity less the applicable energy charge paid by the enstoner under customer's applicable firm tariff. The average cost of combustion turbine capacity will be determined by multiplying the monthly average cost of natural gas per minbfu used to supply its combustion turbine capacity times a heat rate of 10,764 btu's per kWh. Actual interrupted energy shall be determined by accumulating the kW of interrupted demand over the interruption period during any month.

Failure of Customer to curtail when requested to do so may result in termination of service under this rider.

BUY THROUGH OPTION

Upon notification of a request for interruption, customer will be offered the option of purchastingenergy at the Company's avoided cost, based on prevailing market conditions, in lieu of being interrupted. The Company shall provide customer with the cost, in dollars per mWh, associated with such buy through energy, based on the Company's best estimate at the time. In addition, the Company shall be permitted to charge customer a transaction fee of one-half (0.5) mill per kWh to cover the costs of obtaining the buy-through energy. This buy through provision shall only apply in the event of a Company request for an economic interruption. It shall not be applicable in the event of a request to interrupt for reliability reasons, as determined by the Company's system operators.

TERM OF CONTRACT

The minimum original contract period shall be one year and thereafter until terminated by giving at least 6 months previous written notice, but Company may require that contract be executed for a longer initial term when deemed necessary by the size of the load or other conditions.

TERMS AND CONDITIONS

Except as specified above, all other provisions of the power rate to which this schedule is a rider shall apply

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