COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

APPLICATION OF LOUISVILLE GAS AND ELECTRIC	**)**	
COMPANY FOR AN ADJUSTMENT OF ITS	**)**	
ELECTRIC AND GAS RATES, A CERTIFICATE	**)**	**CASE NO.**
OF PUBLIC CONVENIENCE AND NECESSITY,	**)**	**2012-00222**
APPROVAL OF OWNERSHIP OF GAS SERVICE LINES	**)**	
AND RISERS, AND A GAS LINE SURCHARGE	**)**	

RESPONSE OF
LOUISVILLE GAS AND ELECTRIC COMPANY
TO
COMMISSION STAFF'S THIRD REQUEST FOR INFORMATION
DATED AUGUST 28, 2012

FILED: SEPTEMBER 12, 2012

VERIFICATION

COMMONWEALTH OF KENTUCKY)
) SS:
COUNTY OF JEFFERSON)

The undersigned, **Lonnie E. Bellar**, being duly sworn, deposes and says that he is Vice President, State Regulation and Rates for Louisville Gas and Electric Company and Kentucky Utilities Company and an employee of LG&E and KU Services Company, and that he has personal knowledge of the matters set forth in the responses for which he is identified as the witness, and the answers contained therein are true and correct to the best of his information, knowledge and belief.

Lonnie E. Bellar

Lonnie E. Bellar

Subscribed and sworn to before me, a Notary Public in and before said County and State, this 10th day of September 2012.

(SEAL)
Notary Public

My Commission Expires:

July 21, 2015

VERIFICATION

COMMONWEALTH OF KENTUCKY)
) **SS:**
COUNTY OF JEFFERSON)

The undersigned, **Shannon L. Charnas**, being duly sworn, deposes and says that she is Director, Accounting and Regulatory Reporting for LG&E and KU Services Company, and that she has personal knowledge of the matters set forth in the responses for which she is identified as the witness, and the answers contained therein are true and correct to the best of her information, knowledge and belief.

Shannon L. Charnas
Shannon L. Charnas

Subscribed and sworn to before me, a Notary Public in and before said County and State, this 10th day of September 2012.

Joan A. Henry (SEAL)
Notary Public

My Commission Expires:

July 21, 2015

VERIFICATION

COMMONWEALTH OF KENTUCKY)
) **SS:**
COUNTY OF JEFFERSON)

The undersigned, **Robert M. Conroy**, being duly sworn, deposes and says that he is Director - Rates for LG&E and KU Services Company, and that he has personal knowledge of the matters set forth in the responses for which he is identified as the witness, and the answers contained therein are true and correct to the best of his information, knowledge and belief.

Robert M. Conroy

Robert M. Conroy

Subscribed and sworn to before me, a Notary Public in and before said County and State, this 10th day of September 2012.

Tora A. Ginsey (SEAL)

Notary Public

My Commission Expires:

July 21, 2015

VERIFICATION

COMMONWEALTH OF KENTUCKY)
) SS:
COUNTY OF JEFFERSON)

The undersigned, **J. Clay Murphy**, being duly sworn, deposes and says that he is Director – Gas Management, Planning, and Supply for Louisville Gas and Electric Company, and that he has personal knowledge of the matters set forth in the responses for which he is identified as the witness, and the answers contained therein are true and correct to the best of his information, knowledge and belief.

J. Clay Murphy
J. Clay Murphy

Subscribed and sworn to before me, a Notary Public in and before said County and State, this 12th day of September 2012.

Rashelle W. Gaines (SEAL)
Notary Public

My Commission Expires:

February 28, 2014

VERIFICATION

COMMONWEALTH OF PENNSYLVANIA)
) **SS:**
COUNTY OF CUMBERLAND)

The undersigned, **John J. Spanos**, being duly sworn, deposes and says that he is the Senior Vice President, Valuation and Rate Division, for Gannett Fleming, Inc., that he has personal knowledge of the matters set forth in the responses for which he is identified as the witness, and the answers contained therein are true and correct to the best of his information, knowledge and belief.

John J. Spanos
JOHN J. SPANOS

Subscribed and sworn to before me, a Notary Public in and before said County and Commonwealth, this 30th day of August 2012.

(SEAL)
Notary Public

My Commission Expires:

February 20, 2015

COMMONWEALTH OF PENNSYLVANIA
Notarial Seal
Cheryl Ann Rutter, Notary Public
East Pennsboro Twp., Cumberland County
My Commission Expires Feb. 20, 2015
MEMBER, PENNSYLVANIA ASSOCIATION OF NOTARIES

VERIFICATION

COMMONWEALTH OF KENTUCKY)
) SS:
COUNTY OF JEFFERSON)

The undersigned, **Paul Gregory "Greg" Thomas**, being duly sworn, deposes and says that he is Vice President, Energy Delivery – Distribution Operations for Kentucky Utilities Company and Louisville Gas and Electric Company and an employee of LG&E and KU Services Company, and that he has personal knowledge of the matters set forth in the responses for which he is identified as the witness, and the answers contained therein are true and correct to the best of his information, knowledge and belief.

Paul Gregory Thomas
Paul Gregory "Greg" Thomas

Subscribed and sworn to before me, a Notary Public in and before said County and State, this 10th day of September 2012.

Sean A. Henry (SEAL)
Notary Public

My Commission Expires:

July 21, 2015

VERIFICATION

COMMONWEALTH OF KENTUCKY)
) **SS:**
COUNTY OF JEFFERSON)

The undersigned, **Paul W. Thompson**, being duly sworn, deposes and says that he is Senior Vice President, Energy Services for Kentucky Utilities Company and Louisville Gas and Electric Company and an employee of LG&E and KU Services Company, and that he has personal knowledge of the matters set forth in the responses for which he is identified as the witness, and the answers contained therein are true and correct to the best of his information, knowledge and belief.

____
Paul W. Thompson

Subscribed and sworn to before me, a Notary Public in and before said County and State, this 10th day of September 2012.

______________________________(SEAL)
Notary Public

My Commission Expires:

July 21, 2015

LOUISVILLE GAS AND ELECTRIC COMPANY

CASE NO. 2012-00222

Response to Commission Staff's Third Request for Information
Dated August 28, 2012

Question No. 1

Responding Witness: Paul Gregory "Greg" Thomas

Q-1. Refer to the application, Hermann Exhibit 1, page 4. LG&E states that it proposes to take ownership of and responsibility for customer-owned gas service risers as they are replaced and customer-owned service lines when a new service is installed or existing services are replaced or repaired. LG&E's proposed program will replace all targeted gas risers (approximately 213,000) over a five-year period.

a. Explain whether LG&E considers the replacement of the riser to also be a repair of the service line.

b. Upon replacement of the riser, explain whether the service line will be pressure-tested and, if so, whether LG&E will assume ownership of the service line at this time. If not, explain when LG&E will assume ownership of the service line.

c. Provide the timeframe and plan for replacing and taking ownership of the remaining (approximately 87,000) customer-owned service line risers.

d. Provide the timeframe and plan for replacing and taking ownership of any remaining customer-owned service lines.

e. Explain whether the customer will be responsible for any expenses related to the replacement of the service riser and/or the repair, replacement, or new installation of a service line. If yes, provide details as to the expenses for which the customer will be responsible. If no, describe any educational programs that LG&E will implement to inform customers that any repair/replacement will be performed by LG&E at LG&E's expense.

f. Explain whether LG&E or its contractors repaired, replaced, or newly installed service lines as part of, or during, its main replacement program or at any other time. If so, explain how many service lines LG&E or its contractors have repaired, replaced, or newly installed and whether LG&E assumed ownership of those service lines. If LG&E has not assumed ownership of such lines, explain why it hasn't and when it will assume ownership of those lines.

A-1. a. LG&E does not consider the replacement of a target gas riser to be a repair of a customer service line.

b. After completing a riser replacement, LG&E will perform air and operating pressure tests on the service line in accordance with its standard test-and-reconnect procedures. If no additional service is required, LG&E will not assume responsibility for or ownership of the service line. If a repair is needed, LG&E or its contractors will perform the repair and LG&E will assume going-forward responsibility for the service line. LG&E will not, however, assume ownership of the service line for the capital associated with the service line. If the repair requires the Company to make a capital investment, such as the replacement of a gas meter loop, LG&E will only assume ownership for the specific asset that is installed. If the testing reveals that replacement of the entire service line is necessary, LG&E or its contractors will perform the replacement and LG&E will assume going-forward responsibility for and ownership of the service line.

c. Remaining customer risers are of a material and design not targeted for replacement. As such, these risers would not be owned by LG&E until the need for replacement arises, which is dependent upon many variables, including the age and condition of the riser. Because of these variables, the Company cannot provide a more meaningful timeframe.

d. Under LG&E's proposal, the Company will assume responsibility for replacing, repairing, maintaining, and operating all customer service lines whenever conditions dictate. As explained in subpart b., LG&E will only assume ownership of existing customer service lines upon replacement by an LG&E employee or contractor. As explained in subpart c., many variables, including the age, condition, and type of material, affect when a service line will need to be replaced. Because of these variables, the Company cannot provide a more definite timeframe that is meaningful.

e. Upon approval of the proposed Customer Service Ownership Program, LG&E gas customers will be responsible for expenses associated with service line or riser repair, replacement, or installation under the following scenarios:

   a. Relocation of a Company-owned service is needed to accommodate a customer request (such as a house addition);
   b. Repair or replacement of a Company-owned service is needed due to damages resulting from negligence by the customer or an agent of the customer; and

c. Customer initiated accelerated replacement of a customer-owned service riser in advance of the Company's proposed Riser Replacement Program.

Upon approval of the proposed Customer Service Ownership Program, LG&E will educate customers on the program components through multiple communications mediums, including face-to-face communications, bill-inserts, hang cards, direct mailings (in advance of leak survey and main replacement activities), and the Company's web page. LG&E's Customer Piping Handbook will also be revised and distributed to new customers, plumbing supply houses, and local plumbers. A 2013 customer communications plan and schedule will be finalized during the fourth quarter of 2012.

f. LG&E and its contractors have replaced approximately 60,000 customer-owned service lines as part of its main replacement programs, but LG&E has not assumed ownership of any service lines. LG&E replaced certain gas mains to address potential safety concerns. The new mains operate at higher service pressures than the mains they replaced, rendering affected customers' service lines obsolete. To ensure continuity of service and avoid potential safety concerns, LG&E replaced affected customers' service lines to ensure they would be able to tolerate the increased service pressures.

As part of its Customer Service Replacement Business, LG&E and its contractors replaced nearly 11,000 customer-owned service lines between 1996 and 2003 through private contracts with customers. LG&E did not assume ownership of the service lines after their replacement as related expenses were paid for by impacted customers.

Also, as described in Hermann Testimony Exhibit 1, LG&E has replaced 370 failed customer-owned gas service risers.

With the exception of customer service lines installed as part of its gas main replacement programs, LG&E does not currently repair or install customer service lines. LG&E does routinely assist customers with minor repairs, such as tightening leaking fittings.

LG&E did not take ownership of, or responsibility for, any of the customer service lines or gas risers described above because it had not sought Commission approval under 807 KAR 5:022(17)(a)(2) to take such ownership. LG&E is seeking such approval in this proceeding to take ownership of, and responsibility for, customer service lines and gas risers it repairs, replaces, or installs in the future. Therefore, LG&E will eventually take ownership of the customer service lines and gas risers it has already replaced as it repairs or replaces them in the future.

LOUISVILLE GAS AND ELECTRIC COMPANY

CASE NO. 2012-00222

Response to Commission Staff's Third Request for Information
Dated August 28, 2012

Question No. 2

Responding Witness: Paul Gregory "Greg" Thomas

Q-2. Refer to the application, Hermann Exhibit 1, page 6. LG&E states that, after program implementation, it will provide an operator qualified inspector to assure the installer adheres to manufacturer recommendations and Company standards. It also states that LG&E will provide an operator qualified inspector for tasks completed by plumbers.

a. Explain how LG&E will comply with the requirements of 49 CFR 192 Subpart N – Qualification of Pipeline Personnel as it relates to the riser replacement program and the assumption of ownership of the service line.

b. Explain whether the installer/plumber will fulfill the requirements for operator qualification of individuals performing covered tasks on a pipeline facility.

c. Explain whether LG&E will qualify these individuals under its qualification program and maintain the proper records.

d. If the installer/plumber is not operator qualified, explain whether the operator qualified inspector provided by LG&E will be on-site at all times to direct and observe the installer/plumber.

e. Explain whether LG&E anticipates hiring any additional inspectors as part of this replacement program.

A-2. a. All covered tasks as it relates to the riser replacement program and the assumption of ownership of the service line will be completed by an operator qualified agent of the Company.

For customers who elect to accelerate replacement of target gas service risers and hire a third party installer, an operator qualified LG&E representative will direct and observe the installer throughout the replacement of the customer gas service riser. The LG&E representative will then pressure test all replaced gas service risers prior to reestablishing service to customers.

LG&E will only assume ownership of customer risers and services replaced by an LG&E employee or contractor.

b. Third party installers hired by customers who wish to accelerate riser replacement of their gas service riser will work under the direction and observation of an LG&E Operator Qualified employee.

c. LG&E will not qualify third party installers under its Operator Qualification programs.

d. Yes. An LG&E operator qualified representative will be on site at all times to direct and observe the installer.

e. LG&E currently does not anticipate the need for additional inspectors; however, in the future, LG&E will staff its inspector resources commensurate with customer demand for accelerated replacement.

LOUISVILLE GAS AND ELECTRIC COMPANY

CASE NO. 2012-00222

Response to Commission Staff's Third Request for Information
Dated August 28, 2012

Question No. 3

Responding Witness: Paul Gregory "Greg" Thomas

Q-3. Refer to existing PSC Gas No. 8, Original Sheet No. 98, which states "Company will furnish, install, and maintain at its expense the necessary meter, regulator, and connections appurtenant thereto . . . ."

a. Explain whether LG&E currently performs operation and maintenance tasks on service lines, meters, regulators, and appurtenances.

b. If yes, explain what operation and maintenance tasks are currently performed on service lines, meters, regulators, and appurtenances.

A-3. a. Yes. LG&E currently furnishes, installs, and maintains at its expense the necessary service connection extending from its main to the customer's nearest property line. LG&E also furnishes, installs, and maintains at its expense the necessary meter, regulator, and connection appurtenant thereto.

b. LG&E operates, maintains, and inspects service and meter components described in a. above as required by 807 KAR 5:022 and 49 CFR Part 192.

LG&E surveys customer owned service lines and meter piping between the customer property line and Company meter to identify unsafe conditions. Customers are responsible for maintaining their service line and meter piping between the property line and customer meter.

LOUISVILLE GAS AND ELECTRIC COMPANY

CASE NO. 2012-00222

Response to Commission Staff's Third Request for Information
Dated August 28, 2012

Question No. 4

Responding Witness: Paul Gregory "Greg" Thomas

Q-4. Refer to the application, Hermann Exhibit 1, page 6, which states that ownership of customer service lines will result in estimated incremental operations and maintenance costs of $1.1 million in year one and $6.1 million over the five-year riser replacement program, and estimated incremental capital expenses of $6.4 million in year one and nearly $34 million over the five-year riser replacement program, and that these costs will continue thereafter.

a. Explain whether the estimated incremental costs are in addition to or inclusive of the costs associated with the existing operation and maintenance tasks performed in regards to service lines, risers, meters, regulators, and appurtenances.

b. Provide details of the expenses associated with the existing operation and maintenance tasks performed in regards to service lines, risers, meters, regulators, and appurtenances, as well as details of the estimated incremental operation and maintenance expenses and the estimated incremental capital expenses associated with same.

A-4. a. The estimated incremental costs provided in Hermann Exhibit 1, page 6, are not inclusive of all costs associated with LG&E's existing operations and maintenance tasks performed in regards to service lines, risers, meters, regulators, and appurtenances. Incremental capital costs and avoided expenses associated with the proposed Customer Service Ownership Program are included in the estimate provided in Hermann Exhibit 1, page 6.

b. Detail –

1. Operations and maintenance expenses impacted by the proposed programs are provided in LG&E's response to AG 1 – 355. Remaining expenses are not impacted and reflected in the cost of service filed in the case and recovered through gas base rates.

2. Please see LG&E's response to AG 1 – 355 to obtain the estimated incremental operations and maintenance expenses associated with the proposed Customer Service Ownership Program's incremental operations and maintenance tasks specific to service lines, risers, meters, regulators, and appurtenances.

3. Please see LG&E's response to AG 1 – 355 to obtain the estimated incremental capital costs associated with the proposed Customer Service Ownership Program's incremental installation and replacement tasks specific to service lines, risers, meters, regulators, and appurtenances.

LOUISVILLE GAS AND ELECTRIC COMPANY

CASE NO. 2012-00222

Response to Commission Staff's Third Request for Information
Dated August 28, 2012

Question No. 5

Responding Witness: Paul Gregory "Greg" Thomas

Q-5. Refer to the application, Hermann Exhibit 1, page 7. LG&E states that estimated capital expenses to replace the inventory of program risers over a five-year period are $118.8 million. Provide details/breakdown of the expenses associated with the replacement of the inventory of program risers.

A-5. See the attachment which was included in the response to AG 1-355.

Gas Service Riser and Customer Service Ownership
Budget Implications

	Task Description	Estimated Units (2013)	Unit Costs (Raw)		Estimated Year 1 (2013) Costs (Burdened)		
			Labor	Materials	OPEX	CAPITAL	
1	Repair meter loop leak	**1,500**	$ 70.13	$ 5.00	$ 115,437	$ -	
2	Paint rusty meter loop	**35,000**	$ 32.14	$ 2.00	$ 1,259,020	$ -	
3	Remove tree/vegetation in meter loop	**723**	$ 64.28	$ -	$ 47,800	$ -	
4	Remove meter loop from concrete	**424**	$ 198.70	$ 5.00	$ 87,143	$ -	
5	Provide meter clearance from the ground	**504**	$ 157.79	$ 5.00	$ 82,967	$ -	
6	Install meter protection/barricades	**1,308**	$ 210.38	$ 5.00	$ 284,116	$ -	
7	Install meter brackets (loose meter)	**62**	$ 70.13	$ 5.00	$ 4,771	$ -	
8	Repair unlocatable customer services	**562**	$ 385.70	$ 5.00	$ 220,604	$ -	
9	Cut and Cap	**(1,176)**	$ 151.94	$ 5.00	$ (186,718)	$ -	
10	Test and Reconnect	**(1,975)**	$ 79.24	$ 10.00	$ (354,596)	$ -	
11	Turn Off/Turn On	**(2,465)**	$ 33.02	$ -	$ (176,765)	$ -	
12	Spot/Inspect Customer Service	**(512)**	$ 32.40	$ -	$ (36,049)	$ -	
13	Replace Failed Service Risers - Failure Assessment (2011 Baseline Expense)	**(340)**			$ (53,583)		
14	Gas Service Survey (2011 Baseline Expense)	**(300,000)**			$ (142,309)		
15	Leak Survey Target Service Risers (Incremental - 2/3)	**94,806**	$ 7.48	$ -	$ 903,459	$ -	
16	Acclerated Riser Replacements - Cut & Cap, Operator Qualification Inspection, Test and Reconnect (5% of customers accelerate replacement).	**9,065**	$ 228.91	$ -	$ 2,091,670	$ -	
17	Install commercial meter set	**50**	$ 2,700.65	$ 110.00	$ -	$ 313,605	
18	Install industrial meter set	**3**	$ 31,872.92	$ 236.00	$ -	$ 218,320	
19	Install large residential meter set	**560**	$ 174.98	$ 110.00	$ -	$ 295,244	
20	Install Customer Service (New Business)	**2,000**	$ 455.83	$ 150.00	$ -	$ 1,406,767	
21	Replace Cust Services as Comp Service is Replaced	**2,000**	$ 689.59	$ 68.00	$ -	$ 1,758,243	
22	Replace Customer Services	**2,400**	$ 689.59	$ 175.00	$ -	$ 2,407,266	
25	Replace Target Customer Owned Gas Service Risers	**213,303**	$ 368.17	$ 107.94	$ -	$ 117,993,498	$ 553

	Alternative Description	2013	2014	2015	2016	2017	Totals
1	**Implement program to replace all target customer owned gas service risers and assume ownership of cust service lines and risers as they are replaced**						
	Opex	**$ 4,147,055**	**$ 2,156,437**	**$ 1,881,751**	**$ 1,595,027**	**$ 1,296,405**	**$ 11,076,675**
	Ongoing Maintenance and Repairs (Tasks 1-14)	$ 1,151,839	$ 1,186,394	$ 1,221,986	$ 1,258,646	$ 1,296,405	**$ 6,115,270**
	Leak Survey Remaining Target Risers Annually (Task 15)	$ 903,459	$ 663,025	$ 450,950	$ 229,917	$ -	**$ 2,247,351**
	Accelerated Customer Riser Replacements (Task 16 @ 5% of Target Totals - year 1)	$ 2,091,757	$ 307,018	$ 208,815	$ 106,464	$ -	**$ 2,714,054**
	Capital	**$ 24,098,470**	**$ 31,125,964**	**$ 31,782,019**	**$ 32,516,320**	**$ 33,228,918**	**$ 152,751,690**
	Ongoing Construction and Replacement (Tasks 17-22)	$ 6,399,445	$ 6,591,428	$ 6,789,171	$ 6,992,846	$ 7,202,632	**$ 33,975,523**
	Replace Target Customer Owned Gas Service Risers (Task 25)	$ 17,699,025	$ 24,534,536	$ 24,992,848	$ 25,523,473	$ 26,026,286	**$ 118,776,168**

Target Gas Service Risers **213,303**

	2013	2014	2015	2016	2017		
Riser Replacement Costs	**$ 17,699,025**	**$ 24,534,536**	**$24,992,848**	**$25,523,473**	**$ 26,026,286**	**$ 118,776,168**	
Unit Rates	$553.17	$569.77	$586.86	$604.47	$622.60		
Company Replacements	31,995	43,061	42,587	42,225	41,802		**15% Year 1 - due to ramp up time needed**
Minus Company Replacements	181,308	129,182	85,303	42,225	-		
Acclerated Replacements (5% of remaining target risers)	**9,065**	**1,292**	**853**	**422**	-		
End of Year Inventory	**172,242**	**127,890**	**84,449**	**41,802**	**-**		
Accelerated Gas Service Riser Replacements	**$ 2,091,757**	**$ 307,017.61**	**$ 208,815**	**$ 106,464.29**	**$ -**	**$ 2,714,054**	**Tracking Mechanism**
Unit Rate	$ 230.74	$ 237.66	$ 244.79	$ 252.14	0		
Incremental Leak Survey $ per year	**$ 903,459**	**$ 663,025**	**$ 450,950**	**$ 229,917**	**$ -**	**$ 2,247,351**	**Incremental OPEX for 5 year program**
Unit Rate	**$ 7.48**	**$ 7.70**	**$ 7.94**	**$ 8.17**	**$ -**		
# Per Year	120,860	86,035	56,811	28,122	0		

21.25

LG&E Gas Distribution

Gas Service Maintenance, Operations, Repair, and Construction Costs

Task #	Description	Units	Labor Hours: Travel Time	Labor Hours: Staging	Labor Hours: Field Work	Labor Hours: Closing	Admin	Crew Size	Job Description	Labor Resource	Unburdened Unit Costs: Labor	Unburdened Unit Costs: Materials	Burdened Total Costs: Labor	Burdened Total Costs: Materials	Total
							OPEX								
1	Repair meter loop leak	**1,500**	0.5	0.1	0.5	0.1	$ 1.83	1	A	2	$ 70.13	$ 5.00	$ 107,937	$ 7,500	**$ 115,437**
2	Paint rusty meter loop	**35,000**	0.1	0.1	0.3	0.1	$ 1.83	1	A	2	$ 32.14	$ 2.00	$ 1,189,020	$ 70,000	**$ 1,259,020**
3	Remove tree/vegetation in meter loop	**723**	0.5	0.1	0.4	0.1	$ 1.83	1	A	2	$ 64.28	$ -	$ 47,800	$ -	**$ 47,800**
4	Remove meter loop from concrete	**424**	0.5	0.1	1.0	0.1	$ 1.83	2	A	2	$ 198.70	$ 5.00	$ 85,023	$ 2,120	**$ 87,143**
5	Provide meter clearance from the ground	**504**	0.5	0.1	2.0	0.1	$ 1.83	1	A	2	$ 157.79	$ 5.00	$ 80,447	$ 2,520	**$ 82,967**
6	Install meter protection/barricades	**1,308**	0.5	0.2	1.0	0.1	$ 1.83	2	A	2	$ 210.38	$ 5.00	$ 277,576	$ 6,540	**$ 284,116**
7	Install meter brackets (loose meter)	**62**	0.5	0.1	0.5	0.1	$ 1.83	1	A	2	$ 70.13	$ 5.00	$ 4,461	$ 310	**$ 4,771**
8	Repair unlocatable customer services	**562**	0.5	0.2	2.5	0.1	$ 1.83	2	A	2	$ 385.70	$ 5.00	$ 217,794	$ 2,810	**$ 220,604**
9	Cut and Cap	**(1,176)**	0.5	0.2	0.5	0.1	$ 1.83	2	A	2	$ 151.94	$ 5.00	$ (180,838)	$ (5,880)	**$ (186,718)**
10	Test and Reconnect	**(1,975)**	0.5	0.1	0.5	0.1	$ 1.83	2	A	1	$ 79.24	$ 10.00	$ (334,846)	$ (19,750)	**$ (354,596)**
11	Turn Off/Turn On	**(2,465)**	0.5	0.1	0.3	0.1	$ 1.83	1	A	1	$ 33.02	$ -	$ (176,765)	$ -	**$ (176,765)**
12	Spot/Inspect Customer Service	**(512)**	0.5	0.1	0.5	0.1	$ 1.83	1	D	1	$ 32.40	$ -	$ (36,049)	$ -	**$ (36,049)**
	Total On-Going Opex														**$ 1,383,780**
15	Leak Survey Target Service Risers (Incremental - 2/3)	**120,751**	0.1	0.0	0.1	0.1	$ -	1	C	2	$ 7.48	$ -	$ 903,459	$ -	**$ 903,459**
16	Acclerated Riser Replacements - Cut & Cap, Operator Qualification Inspection, Test and Reconnect **(5% of customers accelerate replacement).**	**9,065**	0.25	0.1	1.6	0.05	$ 1.83	2	A	2	$ 228.91	$ -	$ 2,091,670	$ -	**$ 2,091,670**
							Capital								
17	Install commercial meter set	**50**	0.5	0.2	40.0	0.2	1.83	2	A	1	$ 2,700.65	$ 110.00	$ 307,236	$ 6,369	**$ 313,605**
18	Install industrial meter set	**3**	0.5	0.2	160.0	0.2	1.83	6	A	1	$ 31,872.92	$ 236.00	$ 217,500	$ 820	**$ 218,320**
19	Install large residential meter set	**560**	0.5	0.2	1.8	0.2	1.83	2	A	1	$ 174.98	$ 110.00	$ 223,911	$ 71,333	**$ 295,244**
20	Install Customer Service (New Business)	**2,000**	0.5	0.2	3.0	0.2	1.83	2	A	2	$ 455.83	$ 150.00	$ 1,059,367	$ 347,400	**$ 1,406,767**
21	Install Customer Riser (New Business)	**2,000**	0.5	0.2	0.3	0.2	1.83	2	A	2	$ 134.41	$ 68.00	$ 314,958	$ 157,488	**$ 472,446**
22	Replace Customer Services	**2,400**	0.5	0.2	5.0	0.2	1.83	2	A	2	$ 689.59	$ 175.00	$ 1,920,906	$ 486,360	**$ 2,407,266**
23	Install Riser on Customer Service Replacements	**2,400**	0.5	0.2	0.3	0.2	1.83	1	A	2	$ 67.21	$ 68.00	$ 191,171	$ 188,986	**$ 380,157**
24	Replace Cust Services as Comp Service is Replaced	**2,000**	0.5	0.2	5.0	0.2	1.83	2	A	2	$ 689.59	$ 68.00	$ 1,600,755	$ 157,488	**$ 1,758,243**
25	Replace Target Customer Owned Gas Service Risers	**213,303**	0.5	0.2	2.3	0.2	1.83	2	A	2	$ 368.17	$ 107.94	$ 91,330,623	$ 26,662,875	**$ 117,993,498**

Job #	Job Description	1: Company Labor Rate	2: Contractor Labor Rate
A	Gas Mechanic	$ 33.02	$ 58.44
B	Gas Inspector	$ 33.59	$ 58.44
C	Leak Inspector	NA	$ 24.94
D	General Laborer	$ 27.00	$ 47.79

Indirect Costs			
Labor		Contractor & Materials	
OPEX	Capital	OPEX	Capital
111.66%	127.46%	0.00%	15.80%

	Existing Accounting Numbers			2013 Accounting Numbers			Baseline Expenditures			Tracking Mechanism - OPEX Impacts			
Work Description	Project	Task	CAPEX / OPEX	Project	Task	CAPEX / OPEX	April 1, 2011 - December 31, 2011	January 1, 2012 - March 31, 2012	Test Year Expenditures	Leak Mitigation	Customer Service Ownership	Gas Service Risers	Assumptions
Test and Reconnect	CUST419G	TC	OPEX	OCUST419	TBD	OPEX	$ 268,423	$ 69,841	**$ 338,264**	$ -	$ (338,264)	$ -	100% capital after obtaining approval to own CU service
Test and Reconnect (Bardstown)	101763	TR	OPEX	OCUST419	TBD	OPEX	$ 2,412	$ 1,236	**$ 3,648**	$ -	$ (3,648)	$ -	100% capital after obtaining approval to own CU service
Test and Reconnect (Mul)	123846	TR	OPEX	123846	TR	OPEX	$ 677	$ 1,021	**$ 1,698**	$ -	$ (1,698)	$ -	100% capital after obtaining approval to own CU service
Test and Reconnect (Mag)	101764	TR	OPEX	101764	TR	OPEX	$ 8,627	$ 2,358	**$ 10,985**	$ -	$ (10,985)	$ -	100% capital after obtaining approval to own CU service
Cut and Cap (LG&E)	CUST419G	CC	OPEX	OCUST419	TBD	OPEX	$ 133,648	$ 42,806	**$ 176,454**	$ -	$ (176,454)	$ -	Should reduce drastically after obtaining approval to own CU service; transition to primarily capital expense associated with CU service work.
Cut and Cap (Bardstown)	101761	CC	OPEX	OCUST420	TBD	OPEX	$ 1,057	$ -	**$ 1,057**	$ -	$ (1,057)	$ -	
Cut and Cap (Mag)	124844	CC	OPEX	123844	CC	OPEX	$ 6,863	$ -	**$ 6,863**	$ -	$ (6,863)	$ -	
Cut and Cap (Mul)	101762	CC	OPEX	101762	CC	OPEX	$ 2,205	$ 247	**$ 2,452**	$ -	$ (2,452)	$ -	
Information to Customer	CUST419G	IF	OPEX	OCUST419	TBD	OPEX	$ 54,078	$ 14,032	**$ 68,110**	$ -	$ (34,055)	$ -	CU service related information requests should drop about 50%.
Inspect CU Facilities	124598	INSP	OPEX	124598	INSP	OPEX	$ 1,320	$ 647	**$ 1,967**	$ -	$ (1,967)	$ -	
Turn off	CUST419G	TF	OPEX	OCUST419	TBD	OPEX	$ 63,125	$ 23,754	**$ 86,879**	$ -	$ (43,440)	$ -	Turn offs to facilitate customer repair/installation work on CU service to be reduced 50%.
Turn on	CUST419G	TON	OPEX	OCUST419	TBD	OPEX	$ 188,799	$ 57,261	**$ 246,060**	$ -	$ (123,030)	$ -	Turn ons to facilitate customer repair/installation work on CU service to be reduced 50%.
Turn on/Off (Mag)	123840	TO	OPEX	123840	TO	OPEX	$ 13,785	$ 4,507	**$ 18,292**	$ -	$ (9,146)	$ -	Turn ons to facilitate customer repair/installation work on CU service to be reduced by roughly 50%.
Turn On/Off (Bardstown)	101481	TO	OPEX	OCUST420	TBD	OPEX	$ 2,048	$ 427	**$ 2,475**	$ -	$ (1,238)	$ -	Turn ons to facilitate customer repair/installation work on CU service to be reduced 50%.
Install Repair Clamp	LEAK419G	CLAMP	OPEX	OLEAK419	TBD	OPEX	$ 356,233	$ 182,883	**$ 539,116**	$ (107,823)	$ -	$ -	Leaks should reduce as Leak Mitigation Program expands - 20%.
Seal Cast Iron Joints	LEAK419G	JOINTS	OPEX	OLEAK419	TBD	OPEX	$ 45,459	$ 12,321	**$ 57,780**	$ (57,780)	$ -	$ -	Joint sealing should ultimately be eliminated when the LSMR program has been completed (100% eliminated by 2016).
Repair Service	LEAK419G	RS	OPEX	OLEAK419	TBD	OPEX	$ 144,514	$ 85,522	**$ 230,036**	$ (23,004)	$ -	$ -	Company service repairs reduced through leak elimination program - 10%.
Repair/Curb Co Service (Mag)	101498	CS	OPEX	OLEAK420	TBD	OPEX	$ 1,219	$ -	**$ 1,219**	$ (122)	$ -	$ -	Company service repairs reduced through leak elimination program - 10%.
Repair/Curb Co Service (Mul)	101497	CS	OPEX	101497	CS	OPEX	$ 11,194	$ 5,055	**$ 16,249**	$ (1,625)	$ -	$ -	Company service repairs reduced through leak elimination program - 10%.
Dewater main or service	TRLB419G	DWMS	OPEX	OTBRD419	TBD	OPEX	$ 31,715	$ 4,887	**$ 36,602**	$ (29,282)	$ -	$ -	Should be reduced drastically with elimination of LP - 80%
Failed Gas Service Riser Replacements	TRLB419G	SHA	OPEX	OTBRD419	TBD	OPEX	$ 40,941	$ 12,642	**$ 53,583**	$ -	$ (53,583)	$ -	100% capital after obtaining approval to own CU service
Target Gas Service Riser Survey	124928	RISERSURVEY	OPEX	124928	RISERSURVEY	OPEX	$ 142,245	$ 64	**$ 142,309**	$ -	$ -	$ (142,309)	Survey conducted during baseline period to identify target risers.
Incremental Work Tasks													
Repair Meter Loop Leak	NA	NA	NA	TBD	TBD	OPEX	$ -	$ -	$ -	$ -	$ 115,437	$ -	100% of tasks after obtaining approval to own CU Service
Paint Rusty Meter Loop	NA	NA	NA	TBD	TBD	OPEX	$ -	$ -	$ -	$ -	$ 1,259,020	$ -	100% of tasks after obtaining approval to own CU Service
Remove tree/vegetation in meter loop	NA	NA	NA	TBD	TBD	OPEX	$ -	$ -	$ -	$ -	$ 47,800	$ -	100% of tasks after obtaining approval to own CU Service
Remove Meter Loop from Concrete	NA	NA	NA	TBD	TBD	OPEX	$ -	$ -	$ -	$ -	$ 87,143	$ -	100% of tasks after obtaining approval to own CU Service
Provide Meter Clearance from Ground	NA	NA	NA	TBD	TBD	OPEX	$ -	$ -	$ -	$ -	$ 82,967	$ -	100% of tasks after obtaining approval to own CU Service
Install Meter Protection/ Barricades	NA	NA	NA	TBD	TBD	OPEX	$ -	$ -	$ -	$ -	$ 284,116	$ -	100% of tasks after obtaining approval to own CU Service
Install Meter Brackets	NA	NA	NA	TBD	TBD	OPEX	$ -	$ -	$ -	$ -	$ 4,771	$ -	100% of tasks after obtaining approval to own CU Service
Repair Unlocatable Customer Services	NA	NA	NA	TBD	TBD	OPEX	$ -	$ -	$ -	$ -	$ 220,604	$ -	100% of tasks after obtaining approval to own CU Service
Accelerated Customer Riser Replacements	NA	NA	NA	TBD	TBD	OPEX	$ -	$ -	$ -	$ -	$ -	$ 2,091,757	OPEX expenses associated with OpQual, TR, and CC expenses for customers that accelerate replacement.
Incremental Leak Survey for Target Gas Service Risers	NA	NA	NA	TBD	TBD	OPEX	$ -	$ -	$ -	$ -	$ -	$ 903,458	80% of 2/3 of target risers in year 1; trending lower as risers are replaced.
							$ 1,520,587	**$ 521,511**	**$ 2,042,098**	**$ (219,635)**	**$ 1,293,979**	**$ 2,852,906**	

	Existing Accounting Numbers			2013 Accounting Numbers			Baseline Expenditures			Tracking Mechanism Projects - Impacts			
Work Description	**Project**	**Task**	**CAPEX / OPEX**	**Project**	**Task**	**CAPEX / OPEX**	**April 1, 2011 - December 31, 2012**	**January 1, 2012 - March 31, 2013**	**Test Year Expenditures**	**Leak Mitigation**	**Customer Service Ownership**	**Gas Service Risers**	**Assumptions**
Service renewals	RRCS419G	IN	CAPEX	RRCS419G	IN	CAPEX	$ 1,212,948	$ 363,148	**$ 1,576,096**	$ (157,610)	$ -	$ -	Company service renewals reduced 10% by LMP.
Accrual	RRCS419G	CAPACCRUAL	CAPEX	RRCS419G	CAPACCRUAL	CAPEX	$ 53,440	$ 33,698	**$ 87,138**	$ (8,714)	$ -	$ -	Company service renewals reduced 10% by LMP.
Service Renewals Investment	RRCS419G	I	CAPEX	RRCS419G	I	CAPEX	$ 2,929	$ 326	**$ 3,255**	$ (326)	$ -	$ -	Company service renewals reduced 10% by LMP.
Renew Co Service	RRCS419G	IN-C	CAPEX	RRCS419G	IN-C	CAPEX	$ 117,429	$ -	**$ 117,429**	$ (11,743)	$ -	$ -	Company service renewals reduced 10% by LMP.
Renew Co Service	RRCS422G	I	CAPEX	RRCS422G	I	CAPEX	$ 1,774	$ 884	**$ 2,658**	$ (266)	$ -	$ -	Company service renewals reduced 10% by LMP.
Rem/Repl Gas Service 421	RRCS421G	I	CAPEX	RRCS421G	I	CAPEX	$ 12,207	$ 11,514	**$ 23,721**	$ (2,372)	$ -	$ -	
Incremental Work Tasks													
Install commercial meter set	NA	NA	NA	TBD	TBD	CAPEX	$ -	$ -	**$ -**	$ -	$ 313,605	$ -	
Install industrial meter set	NA	NA	NA	TBD	TBD	CAPEX	$ -	$ -	**$ -**	$ -	$ 218,320	$ -	
Install large residential meter set	NA	NA	NA	TBD	TBD	CAPEX	$ -	$ -	**$ -**	$ -	$ 295,244	$ -	
Install customer service (NB)	NA	NA	NA	TBD	TBD	CAPEX	$ -	$ -	**$ -**	$ -	$ 1,406,767	$ -	
Replace customer service concurrent with company service replacement	NA	NA	NA	TBD	TBD	CAPEX	$ -	$ -	**$ -**	$ -	$ 1,758,243	$ -	
Replace customer services	NA	NA	NA	TBD	TBD	CAPEX	$ -	$ -	**$ -**	$ -	$ 2,407,266	$ -	
Replace Target Customer Owned Gas Service Risers	NA	NA	NA	TBD	TBD	CAPEX	$ -	$ -	**$ -**	$ -		$ 17,699,025	Year 1 costs for 5 year program.
							$ 1,400,727	**$ 409,570**	**$ 1,810,297**				

LOUISVILLE GAS AND ELECTRIC COMPANY

CASE NO. 2012-00222

Response to Commission Staff's Third Request for Information
Dated August 28, 2012

Question No. 6

Responding Witness: Lonnie E. Bellar

Q-6. Refer to proposed PSC Gas No. 9, Original Sheet No. 98, which states "Customer shall protect such property of Company from loss or damage." Explain whether the customer is proposed to be responsible for protecting the meter set, through activities such as installation of barriers, and any expenses associated with such.

A-6. Under the proposed Customer Service Ownership Program, LG&E will assume responsibility for installing necessary protective barriers for new installations. Consistent with the current tariff, customers shall not permit anyone who is not an agent of the Company to remove, damage, or tamper with Company property.

LOUISVILLE GAS AND ELECTRIC COMPANY

CASE NO. 2012-00222

Response to Commission Staff's Third Request for Information
Dated August 28, 2012

Question No. 7

Responding Witness: Robert M. Conroy

Q-7. Refer to the application, Conroy Exhibits R2 and R7. Provide this schedule for each of the following electric rate classes: GS, PS-Secondary, PS-Primary, TOD-Secondary, TOD-Primary, RTS, and FLS; and for the following gas rate classes: CGS, IGS, AAGS, and FT.

A-7. For the electric rate classes requested, with the exception of Rate FLS, the requested information is contained in "Att-PSC2-108-File03" ('C-2, C-3 LGE Electric Cost of Service Study.xls'); however, certain cells were not updated to include the final results of the cost of service study. LG&E is providing in Excel format an updated cost of service spreadsheet ('C-2, C-3 LGE Electric Cost of Service Study Revised.xlsx'), which incorporates other corrections to the study identified through discovery. The revisions have an immaterial impact on the results of the cost of service study. See Attachment 1 for exhibits similar to Conroy Exhibit R2 for each of the above referenced electric rate classes with the exception of Rate FLS. LG&E does not have any customers on Rate FLS; therefore, there is no cost of service unit cost information. Rate class RS is also included in the attachment in order to reflect the impact of the changes made to the cost of service study.

For the gas rate classes requested, see Attachment 2 for exhibits similar to Conroy Exhibit R7 for each of the above referenced gas rate classes.

One attachment is being provided in a separate file in Excel format.

Louisville Gas and Electric Company
Calculation of Residential Electric Unit Cost
Twelve Months Ended March 31, 2012

Rate RS

	Description	Production		Transmission	Distribution		Customer Service Expenses	
		Demand-Related	Energy-Related	Demand-Related	Demand-Related	Customer-Related	Customer-Related	Total
(1)	Rate Base	$ 496,624,667	$ 20,450,212	$ 50,943,660	$ 126,226,821	$ 234,407,004	$ 2,921,581	$ 931,573,945
(2)	Rate Base Adjustments	(6,282,362)	(258,698)	(644,443)	(1,596,785)	(2,965,277)	(36,958)	$ (11,784,524)
(3)	Rate Base as Adjusted	$ 490,342,304	$ 20,191,514	$ 50,299,217	$ 124,630,036	$ 231,441,727	$ 2,884,622	$ 919,789,421
(4)	Rate of Return	5.66%	5.66%	5.66%	5.66%	5.66%	5.66%	
(5)	Return	$ 27,762,313	$ 1,143,208	$ 2,847,853	$ 7,056,332	$ 13,103,821	$ 163,322	$ 52,076,848
(6)	Interest Expenses	$ 8,941,115	$ 368,181	$ 917,178	$ 2,272,558	$ 4,220,209	$ 52,599	$ 16,771,840
(7)	Net Income	$ 18,821,198	$ 775,027	$ 1,930,675	$ 4,783,774	$ 8,883,612	$ 110,723	$ 35,305,008
(8)	Income Taxes	$ 12,147,663	$ 500,221	$ 1,246,105	$ 3,087,565	$ 5,733,701	$ 71,463	$ 22,786,718
(9)	Operation and Maintenance Expenses	$ 50,820,965	$ 181,316,008	$ 9,182,527	$ 13,017,150	$ 29,038,786	$ 21,930,101	$ 305,305,537
(10)	Depreciation Expenses	$ 37,605,716	$ -	$ 2,629,767	$ 5,900,499	$ 10,921,726	$ -	$ 57,057,708
(11)	Other Taxes	$ 4,427,266	$ -	$ 572,817	$ 1,165,745	$ 2,157,775	$ -	$ 8,323,603
(12)	Other Depreciation Expenses	$ 1,477,622	$ 60,846	$ 151,574	$ 375,566	$ 697,438	$ 8,693	$ 2,771,739
(13)	Curtailable Service Credit	$ 211,010	$ -	$ -	$ -	$ -	$ -	$ 211,010
(14)	Expense Adjustments - Prod. Demand	$ (320,085)	$ -	$ -	$ -	$ -	$ -	$ (320,085)
(15)	Expense Adjustments - Energy	$ -	$ (15,412,944)	$ -	$ -	$ -	$ -	$ (15,412,944)
(16)	Expense Adjustments - Trans. Demand	$ -	$ -	$ (1,066,886)	$ -	$ -	$ -	$ (1,066,886)
(17)	Expense Adjustments - Distribution	$ -	$ -	$ -	$ (3,023,745)	$ (5,615,186)	$ -	$ (8,638,931)
(18)	Expense Adjustments - Other	$ (26,835)	$ (1,105)	$ (2,753)	$ (6,821)	$ (12,666)	$ (158)	$ (50,337)
(19)	Expense Adjustments - Total	$ (346,919)	$ (15,414,049)	$ (1,069,639)	$ (3,030,566)	$ (5,627,852)	$ (158)	$ (25,489,182)
(20)	Total Cost of Service	$ 134,105,636	$ 167,606,235	$ 15,561,004	$ 27,572,291	$ 56,025,395	$ 22,173,421	$ 423,043,982
(21)	Less: Misc Revenue - Energy	$ -	$ 1,005,274	$ -	$ -	$ -	$ -	$ 1,005,274
(22)	Less: Misc Revenue - Other	$ (30,508,367)	$ (1,256,286)	$ (3,129,542)	$ (7,754,295)	$ (14,399,959)	$ (179,477)	$ (57,227,925)
(23)	Less: Misc Revenue - Total	$ (30,508,367)	$ (251,012)	$ (3,129,542)	$ (7,754,295)	$ (14,399,959)	$ (179,477)	$ (56,222,651)
(24)	Net Cost of Service	$ 103,597,269	$ 167,355,223	$ 12,431,462	$ 19,817,996	$ 41,625,436	$ 21,993,944	$ 366,821,331
(25)	Billing Units	4,216,187,376	4,216,187,376	4,216,187,376	4,216,187,376	4,173,222	4,173,222	
(26)	Unit Costs	$ 0.02457	$ 0.03969	$ 0.00295	$ 0.00470	$ 9.97	$ 5.27	$ 15.24

Customer Charge	15.24
Energy Charge	0.071913775
Distribution Customer	15.24
Distribution Customer Margin	0.863
	$ 16.11

Louisville Gas and Electric Company
Calculation of Residential Electric Unit Cost
Twelve Months Ended March 31, 2012

Rate GS

	Description	Production		Transmission	Distribution		Customer Service Expenses	
		Demand-Related	Energy-Related	Demand-Related	Demand-Related	Customer-Related	Customer-Related	Total
(1)	Rate Base	$ 161,886,223	$ 6,828,474	$ 16,606,257	$ 31,085,050	$ 32,718,099	$ 566,603	$ 249,690,706
(2)	Rate Base Adjustments	(2,368,721)	(99,914)	(242,983)	(454,837)	(478,732)	(8,291)	$ (3,653,477)
(3)	Rate Base as Adjusted	$ 159,517,502	$ 6,728,560	$ 16,363,274	$ 30,630,213	$ 32,239,367	$ 558,313	$ 246,037,229
(4)	Rate of Return	12.05%	12.05%	12.05%	12.05%	12.05%	12.05%	
(5)	Return	$ 19,229,090	$ 811,096	$ 1,972,516	$ 3,692,329	$ 3,886,305	$ 67,302	$ 29,658,638
(6)	Interest Expenses	$ 2,957,274	$ 124,740	$ 303,357	$ 567,849	$ 597,681	$ 10,350	$ 4,561,252
(7)	Net Income	$ 16,271,816	$ 686,357	$ 1,669,160	$ 3,124,480	$ 3,288,624	$ 56,952	$ 25,097,386
(8)	Income Taxes	$ 10,512,796	$ 443,437	$ 1,078,401	$ 2,018,645	$ 2,124,694	$ 36,795	$ 16,214,767
(9)	Operation and Maintenance Expenses	$ 16,566,262	$ 60,542,728	$ 2,993,256	$ 3,355,432	$ 4,986,318	$ 5,458,673	$ 93,902,669
(10)	Depreciation Expenses	$ 12,258,447	$ -	$ 857,233	$ 1,452,264	$ 1,506,511	$ -	$ 16,074,456
(11)	Other Taxes	$ 1,443,169	$ -	$ 186,723	$ 286,920	$ 297,637	$ -	$ 2,214,449
(12)	Other Depreciation Expenses	$ 506,270	$ 21,355	$ 51,933	$ 97,213	$ 102,320	$ 1,772	$ 780,862
(13)	Curtailable Service Credit	$ 68,435						$ 68,435
(14)	Expense Adjustments - Prod. Demand	$ (120,755)	$ -	$ -	$ -	$ -	$ -	$ (120,755)
(15)	Expense Adjustments - Energy	$ -	$ (5,131,422)	$ -	$ -	$ -	$ -	$ (5,131,422)
(16)	Expense Adjustments - Trans. Demand	$ -	$ -	$ (347,776)	$ -	$ -	$ -	$ (347,776)
(17)	Expense Adjustments - Distribution	$ -	$ -	$ -	$ (959,133)	$ (1,009,521)	$ -	$ (1,968,654)
(18)	Expense Adjustments - Other	$ (741,315)	$ (31,269)	$ (76,044)	$ (142,346)	$ (149,824)	$ (2,595)	$ (1,143,392)
(19)	Expense Adjustments - Total	$ (862,069)	$ (5,162,691)	$ (423,820)	$ (1,101,479)	$ (1,159,345)	$ (2,595)	$ (8,711,998)
(20)	Total Cost of Service	$ 59,722,398	$ 56,655,925	$ 6,716,241	$ 9,801,325	$ 11,744,441	$ 5,561,947	$ 150,202,278
(21)	Less: Misc Revenue - Energy	$ -	$ 335,668	$ -	$ -	$ -	$ -	$ 335,668
(22)	Less: Misc Revenue - Other	$ (11,721,046)	$ (494,402)	$ (1,202,343)	$ (2,250,650)	$ (2,368,888)	$ (41,024)	$ (18,078,352)
(23)	Less: Misc Revenue - Total	$ (11,721,046)	$ (158,734)	$ (1,202,343)	$ (2,250,650)	$ (2,368,888)	$ (41,024)	$ (17,742,684)
(24)	Net Cost of Service	$ 48,001,353	$ 56,497,191	$ 5,513,899	$ 7,550,674	$ 9,375,553	$ 5,520,924	$ 132,459,594
(25)	Billing Units	1,407,815,493	1,407,815,493	1,407,815,493	1,407,815,493	531,912	531,912	
(26)	Unit Costs	0.034096338	0.040131105	0.003916635	0.005363398	17.63	10.38	$ 28.01

Customer Charge	$ 28.01
Energy Charge	0.083507475
Distribution Customer	28.01
Distribution Customer Margin	3.38
	$ 31.38

Louisville Gas and Electric Company
Calculation of Residential Electric Unit Cost
Twelve Months Ended March 31, 2012

Rate PS-Primary

	Description	Production		Transmission	Distribution		Customer Service Expenses	Total
		Demand-Related	Energy-Related	Demand-Related	Demand-Related	Customer-Related	Customer-Related	
(1)	Rate Base	$ 20,058,263	$ 1,113,808	$ 2,057,573	$ 2,195,733	$ 246,322	$ 2,233	$ 25,673,931
(2)	Rate Base Adjustments	(327,612)	(18,192)	(33,606)	(35,863)	(4,023)	(36)	$ (419,332)
(3)	Rate Base as Adjusted	$ 19,730,652	$ 1,095,616	$ 2,023,966	$ 2,159,870	$ 242,298	$ 2,197	$ 25,254,598
(4)	Rate of Return	12.49%	12.49%	12.49%	12.49%	12.49%	12.49%	
(5)	Return	$ 2,463,727	$ 136,807	$ 252,729	$ 269,699	$ 30,255	$ 274	$ 3,153,491
(6)	Interest Expenses	$ 370,557	$ 20,577	$ 38,012	$ 40,564	$ 4,551	$ 41	$ 474,301
(7)	Net Income	$ 2,093,170	$ 116,231	$ 214,717	$ 229,135	$ 25,705	$ 233	$ 2,679,190
(8)	Income Taxes	$ 1,375,092	$ 76,357	$ 141,057	$ 150,528	$ 16,887	$ 153	$ 1,760,073
(9)	Operation and Maintenance Expenses	$ 2,052,617	$ 9,875,259	$ 370,875	$ 275,129	$ 110,727	$ 26,800	$ 12,711,407
(10)	Depreciation Expenses	$ 1,518,864	$ -	$ 106,214	$ 102,376	$ 11,015	$ -	$ 1,738,469
(11)	Other Taxes	$ 178,814	$ -	$ 23,136	$ 20,226	$ 2,176	$ -	$ 224,352
(12)	Other Depreciation Expenses	$ 65,979	$ 3,664	$ 6,768	$ 7,223	$ 810	$ 7	$ 84,451
(13)	Curtailable Service Credit	$ 7,293						$ 7,293
(14)	Expense Adjustments - Prod. Demand	$ (16,025)	$ -	$ -	$ -	$ -	$ -	$ (16,025)
(15)	Expense Adjustments - Energy	$ -	$ (842,492)	$ -	$ -	$ -	$ -	$ (842,492)
(16)	Expense Adjustments - Trans. Demand	$ -	$ -	$ (43,091)	$ -	$ -	$ -	$ (43,091)
(17)	Expense Adjustments - Distribution	$ -	$ -	$ -	$ (96,412)	$ (10,816)	$ -	$ (107,228)
(18)	Expense Adjustments - Other	$ (131,739)	$ (7,315)	$ (13,514)	$ (14,421)	$ (1,618)	$ (15)	$ (168,622)
(19)	Expense Adjustments - Total	$ (147,764)	$ (849,807)	$ (56,604)	$ (110,833)	$ (12,433)	$ (15)	$ (1,177,457)
(20)	Total Cost of Service	$ 7,514,622	$ 9,242,280	$ 844,173	$ 714,347	$ 159,437	$ 27,220	$ 18,502,080
(21)	Less: Misc Revenue - Energy	$ -	$ 54,752	$ -	$ -	$ -	$ -	$ 54,752
(22)	Less: Misc Revenue - Other	$ (2,024,611)	$ (112,424)	$ (207,684)	$ (221,630)	$ (24,863)	$ (225)	$ (2,591,437)
(23)	Less: Misc Revenue - Total	$ (2,024,611)	$ (57,672)	$ (207,684)	$ (221,630)	$ (24,863)	$ (225)	$ (2,536,686)
(24)	Net Cost of Service	$ 5,490,011	$ 9,184,608	$ 636,489	$ 492,717	$ 134,574	$ 26,995	$ 15,965,394
(25)	Billing Units	652,713	234,484,420	652,713	652,713	1,020	1,020	
(26)	Unit Costs	8.41106353	0.039169373	0.975144109	0.754876179	131.94	26.47	$ 158.40

Customer Charge	$ 158.40
Energy Charge	0.03917
Demand Charge	10.14
Distribution Customer	158.40
Distribution Customer Margin	19.78
	$ 178.18

Louisville Gas and Electric Company
Calculation of Residential Electric Unit Cost
Twelve Months Ended March 31, 2012

Rate PS Secondary

		Production		Transmission	Distribution		Customer Service Expenses	
	Description	**Demand-Related**	**Energy-Related**	**Demand-Related**	**Demand-Related**	**Customer-Related**	**Customer-Related**	**Total**
(1)	Rate Base	$ 222,680,347	$ 11,225,829	$ 22,842,506	$ 35,673,376	$ 3,386,778	$ 76,163	$ 295,884,998
(2)	Rate Base Adjustments	(3,525,683)	(177,738)	(361,664)	(564,814)	(53,623)	(1,206)	$ (4,684,728)
(3)	Rate Base as Adjusted	$ 219,154,663	$ 11,048,091	$ 22,480,842	$ 35,108,562	$ 3,333,156	$ 74,957	$ 291,200,271
(4)	Rate of Return	12.48%	12.48%	12.48%	12.48%	12.48%	12.48%	
(5)	Return	$ 27,354,855	$ 1,379,021	$ 2,806,056	$ 4,382,246	$ 416,044	$ 9,356	$ 36,347,578
(6)	Interest Expenses	$ 4,115,170	$ 207,455	$ 422,133	$ 659,250	$ 62,588	$ 1,407	$ 5,468,005
(7)	Net Income	$ 23,239,685	$ 1,171,566	$ 2,383,922	$ 3,722,996	$ 353,456	$ 7,949	$ 30,879,574
(8)	Income Taxes	$ 14,580,581	$ 735,041	$ 1,495,673	$ 2,335,808	$ 221,758	$ 4,987	$ 19,373,848
(9)	Operation and Maintenance Expenses	$ 22,787,491	$ 99,530,630	$ 4,117,331	$ 3,932,002	$ 797,687	$ 917,514	$ 132,082,655
(10)	Depreciation Expenses	$ 16,861,937	$ -	$ 1,179,155	$ 1,666,186	$ 156,918	$ -	$ 19,864,195
(11)	Other Taxes	$ 1,985,131	$ -	$ 256,844	$ 329,184	$ 31,002	$ -	$ 2,602,161
(12)	Other Depreciation Expenses	$ 726,220	$ 36,610	$ 74,495	$ 116,340	$ 11,045	$ 248	$ 964,959
(13)	Curtailable Service Credit	$ 85,426						$ 85,426
(14)	Expense Adjustments - Prod. Demand	$ (158,123)	$ -	$ -	$ -	$ -	$ -	$ (158,123)
(15)	Expense Adjustments - Energy	$ -	$ (8,422,130)	$ -	$ -	$ -	$ -	$ (8,422,130)
(16)	Expense Adjustments - Trans. Demand	$ -	$ -	$ (478,378)	$ -	$ -	$ -	$ (478,378)
(17)	Expense Adjustments - Distribution	$ -	$ -	$ -	$ (1,048,107)	$ (99,506)	$ -	$ (1,147,612)
(18)	Expense Adjustments - Other	$ (690,501)	$ (34,810)	$ (70,831)	$ (110,618)	$ (10,502)	$ (236)	$ (917,499)
(19)	Expense Adjustments - Total	$ (848,624)	$ (8,456,940)	$ (549,210)	$ (1,158,725)	$ (110,008)	$ (236)	$ (11,123,742)
(20)	Total Cost of Service	$ 83,533,018	$ 93,224,362	$ 9,380,345	$ 11,603,041	$ 1,524,446	$ 931,869	$ 200,197,081
(21)	Less: Misc Revenue - Energy	$ -	$ 551,830	$ -	$ -	$ -	$ -	$ 551,830
(22)	Less: Misc Revenue - Other	$ (20,098,709)	$ (1,013,222)	$ (2,061,722)	$ (3,219,812)	$ (305,684)	$ (6,874)	$ (26,706,023)
(23)	Less: Misc Revenue - Total	$ (20,098,709)	$ (461,393)	$ (2,061,722)	$ (3,219,812)	$ (305,684)	$ (6,874)	$ (26,154,193)
(24)	Net Cost of Service	$ 63,434,309	$ 92,762,970	$ 7,318,623	$ 8,383,229	$ 1,218,762	$ 924,995	$ 174,042,888
(25)	Billing Units	6,013,535	2,314,411,122	6,013,535	6,013,535	34,788	34,788	
(26)	Unit Costs	10.54858901	0.040080593	1.217025087	1.394060033	35.03	26.59	$ 61.62

Customer Charge	$ 61.62
Energy Charge	0.04008
Demand Charge	13.16
Distribution Customer	61.62
Distribution Customer Margin	7.69
	$ 69.32

Louisville Gas and Electric Company
Calculation of Residential Electric Unit Cost
Twelve Months Ended March 31, 2012

Rate TOD Primary

	Description	Production		Transmission	Distribution		Customer Service Expenses	Total
		Demand-Related	Energy-Related	Demand-Related	Demand-Related	Customer-Related	Customer-Related	
(1)	Rate Base	$ 153,844,436	$ 8,991,070	$ 15,781,332	$ 20,556,540	$ 276,576	$ 10,923	$ 199,460,877
(2)	Rate Base Adjustments	(2,475,060.79)	(144,649.01)	(253,891.25)	(330,715.16)	(4,450)	(176)	$ (3,208,942)
(3)	Rate Base as Adjusted	$ 151,369,375	$ 8,846,421	$ 15,527,441	$ 20,225,825	$ 272,126	$ 10,747	$ 196,251,936
(4)	Rate of Return	8.18%	8.18%	8.18%	8.18%	8.18%	8.18%	
(5)	Return	$ 12,378,710	$ 723,444	$ 1,269,806	$ 1,654,031	$ 22,254	$ 879	$ 16,049,123
(6)	Interest Expenses	$ 2,833,840	$ 165,617	$ 290,694.79	$ 378,655	$ 5,095	$ 201	$ 3,674,103
(7)	Net Income	$ 9,544,869	$ 557,827	$ 979,111	$ 1,275,376	$ 17,159	$ 678	$ 12,375,020
(8)	Income Taxes	$ 5,815,726	$ 339,886	$ 596,576	$ 777,092	$ 10,455	$ 413	$ 7,540,148
(9)	Operation and Maintenance Expenses	$ 15,743,323	$ 79,716,775	$ 2,844,564	$ 2,575,770	$ 124,446	$ 145,037	$ 101,149,914
(10)	Depreciation Expenses	$ 11,649,502	$ -	$ 814,649	$ 958,446	$ 12,331	$ -	$ 13,434,929
(11)	Other Taxes	$ 1,371,479	$ -	$ 177,447	$ 189,358	$ 2,436	$ -	$ 1,740,720
(12)	Other Depreciation Expenses	$ 503,382	$ 29,419	$ 51,637	$ 67,261	$ 905	$ 36	$ 652,640
(13)	Curtailable Service Credit	$ (48,638)	$ -	$ -	$ -	$ -	$ -	$ (48,638)
(14)	Expense Adjustments - Prod. Demand	$ (98,564)	$ -	$ -	$ -	$ -	$ -	$ (98,564)
(15)	Expense Adjustments - Energy	$ -	$ (6,741,227)	$ -	$ -	$ -	$ -	$ (6,741,227)
(16)	Expense Adjustments - Trans. Demand	$ -	$ -	$ (330,500)	$ -	$ -	$ -	$ (330,500)
(17)	Expense Adjustments - Distribution	$ -	$ -	$ -	$ (260,197)	$ (3,501)	$ -	$ (263,697)
(18)	Expense Adjustments - Other	$ 9,328	$ 545	$ 957	$ 1,246	$ 17	$ 1	$ 12,094
(19)	Expense Adjustments - Total	$ (89,236)	$ (6,740,681)	$ (329,543)	$ (258,950)	$ (3,484)	$ 1	$ (7,421,895)
(20)	Total Cost of Service	$ 47,324,248	$ 74,068,843	$ 5,425,136	$ 5,963,007	$ 169,343	$ 146,365	$ 133,096,942
(21)	Less: Misc Revenue - Energy	$ -	$ 441,975	$ -	$ -	$ -	$ -	$ 441,975
(22)	Less: Misc Revenue - Other	$ (15,997,346)	$ (934,927)	$ (1,641,005)	$ (2,137,549)	$ (28,759)	$ (1,136)	$ (20,740,722)
(23)	Less: Misc Revenue - Total	$ (15,997,346)	$ (492,951)	$ (1,641,005)	$ (2,137,549)	$ (28,759)	$ (1,136)	$ (20,298,746)
(24)	Net Cost of Service	$ 31,326,902	$ 73,575,891	$ 3,784,131	$ 3,825,458	$ 140,584	$ 145,229	$ 112,798,195
(25)	Billing Units	4,460,699	1,892,845,763	4,460,699	4,460,699	1,128	1,128	
(26)	Unit Costs	$ 7.02287	$ 0.03887	$ 0.84833	$ 0.85759	$ 124.63	$ 128.75	$ 253.38

Customer Charge	$ 253.38
Energy Charge	0.03887
Demand Charge	8.73
Distribution Customer	253.38
Distribution Customer Margin	20.721
	$ 274.10

Louisville Gas and Electric Company
Calculation of Residential Electric Unit Cost
Twelve Months Ended March 31, 2012

Rate TOD Secondary

	Description	Production		Transmission	Distribution		Customer Service Expenses	
		Demand-Related	Energy-Related	Demand-Related	Demand-Related	Customer-Related	Customer-Related	Total
(1)	Rate Base	$ 55,868,829	$ 2,874,938	$ 5,731,014	$ 8,838,355	$ 202,565	$ 18,244	$ 73,533,945
(2)	Rate Base Adjustments	(890,031)	(45,800)	(91,299)	(140,801)	(3,227)	(291)	$ (1,171,449)
(3)	Rate Base as Adjusted	$ 54,978,798	$ 2,829,138	$ 5,639,714	$ 8,697,554	$ 199,338	$ 17,953	$ 72,362,496
(4)	Rate of Return	9.45%	9.45%	9.45%	9.45%	9.45%	9.45%	
(5)	Return	$ 5,196,090	$ 267,384	$ 533,014	$ 822,013	$ 18,840	$ 1,697	$ 6,839,037
(6)	Interest Expenses	$ 1,032,764	$ 53,145	$ 105,941	$ 163,382	$ 3,745	$ 337	$ 1,359,312
(7)	Net Income	$ 4,163,326	$ 214,239	$ 427,073	$ 658,631	$ 15,095	$ 1,360	$ 5,479,725
(8)	Income Taxes	$ 1,722,201	$ 88,622	$ 176,663	$ 272,449	$ 6,244	$ 562	$ 2,266,742
(9)	Operation and Maintenance Expenses	$ 5,717,211	$ 25,489,823	$ 1,033,008	$ 963,116	$ 47,314	$ 255,391	$ 33,505,862
(10)	Depreciation Expenses	$ 4,230,534	$ -	$ 295,841	$ 412,870	$ 9,502	$ -	$ 4,948,748
(11)	Other Taxes	$ 498,054	$ -	$ 64,440	$ 81,570	$ 1,877	$ -	$ 645,942
(12)	Other Depreciation Expenses	$ 182,648	$ 9,399	$ 18,736	$ 28,895	$ 662	$ 60	$ 240,399
(13)	Curtailable Service Credit	$ 20,388						$ 20,388
(14)	Expense Adjustments - Prod. Demand	$ (32,159)	$ -	$ -	$ -	$ -	$ -	$ (32,159)
(15)	Expense Adjustments - Energy	$ -	$ (2,140,162)	$ -	$ -	$ -	$ -	$ (2,140,162)
(16)	Expense Adjustments - Trans. Demand	$ -	$ -	$ (120,022)	$ -	$ -	$ -	$ (120,022)
(17)	Expense Adjustments - Distribution	$ -	$ -	$ -	$ (241,505)	$ (5,535)	$ -	$ (247,040)
(18)	Expense Adjustments - Other	$ 818,104	$ 42,099	$ 83,921	$ 129,423	$ 2,966	$ 267	$ 1,076,779
(19)	Expense Adjustments - Total	$ 785,945	$ (2,098,063)	$ (36,101)	$ (112,083)	$ (2,569)	$ 267	$ (1,462,603)
(20)	Total Cost of Service	$ 18,353,071	$ 23,757,165	$ 2,085,601	$ 2,468,830	$ 81,872	$ 257,976	$ 47,004,515
(21)	Less: Misc Revenue - Energy	$ -	$ 141,324	$ -	$ -	$ -	$ -	$ 141,324
(22)	Less: Misc Revenue - Other	$ (5,167,069)	$ (265,891)	$ (530,037)	$ (817,422)	$ (18,734)	$ (1,687)	$ (6,800,840)
(23)	Less: Misc Revenue - Total	$ (5,167,069)	$ (124,567)	$ (530,037)	$ (817,422)	$ (18,734)	$ (1,687)	$ (6,659,516)
(24)	Net Cost of Service	$ 13,186,002	$ 23,632,598	$ 1,555,564	$ 1,651,408	$ 63,137	$ 256,289	$ 40,344,999
(25)	Billing Units	1,197,033	592,721,353	1,197,033	1,197,033	1,884	1,884	
(26)	Unit Costs	11.01557074	0.039871346	1.299516577	1.379584685	33.51	136.03	$ 169.55

Customer Charge	$ 169.55
Energy Charge	0.03987
Demand Charge	13.69
Distribution Customer	169.55
Distribution Customer Margin	16.024
	$ 185.57

Louisville Gas and Electric Company
Calculation of Residential Electric Unit Cost
Twelve Months Ended March 31, 2012

Rate RTS

	Description	Production		Transmission	Distribution		Customer Service Expenses	
		Demand-Related	Energy-Related	Demand-Related	Demand-Related	Customer-Related	Customer-Related	Total
(1)	Rate Base	$ 44,953,429	$ 2,440,807	$ 4,611,314	$ -	$ 213,301	$ 1,278	$ 52,220,129
(2)	Rate Base Adjustments	(790,848)	(42,940)	(81,125)	-	(3,753)	(22)	$ (918,688)
(3)	Rate Base as Adjusted	$ 44,162,581	$ 2,397,867	$ 4,530,189	$ -	$ 209,549	$ 1,256	$ 51,301,441
(4)	Rate of Return	8.13%	8.13%	8.13%	8.13%	8.13%	8.13%	
(5)	Return	$ 3,591,644	$ 195,013	$ 368,430	$ -	$ 17,042	$ 102	$ 4,172,231
(6)	Interest Expenses	$ 839,486	$ 45,581	$ 86,114	$ -	$ 3,983	$ 24	$ 975,189
(7)	Net Income	$ 2,752,158	$ 149,432	$ 282,316	$ -	$ 13,059	$ 78	$ 3,197,043
(8)	Income Taxes	$ 1,721,721	$ 93,483	$ 176,614	$ -	$ 8,169	$ 49	$ 2,000,036
(9)	Operation and Maintenance Expenses	$ 4,600,208	$ 21,640,721	$ 831,183	$ -	$ 106,432	$ 17,341	$ 27,195,885
(10)	Depreciation Expenses	$ 3,403,991	$ -	$ 238,041	$ -	$ 9,456	$ -	$ 3,651,488
(11)	Other Taxes	$ 400,747	$ -	$ 51,850	$ -	$ 1,868	$ -	$ 454,465
(12)	Other Depreciation Expenses	$ 152,698	$ 8,291	$ 15,664	$ -	$ 725	$ 4	$ 177,381
(13)	Curtailable Service Credit	$ (354,300)						$ (354,300)
(14)	Expense Adjustments - Prod. Demand	$ (26,278)	$ -	$ -	$ -	$ -	$ -	$ (26,278)
(15)	Expense Adjustments - Energy	$ -	$ (1,834,694)	$ -	$ -	$ -	$ -	$ (1,834,694)
(16)	Expense Adjustments - Trans. Demand	$ -	$ -	$ (96,572)	$ -	$ -	$ -	$ (96,572)
(17)	Expense Adjustments - Distribution	$ -	$ -	$ -	$ -	$ -	$ -	$ -
(18)	Expense Adjustments - Other	$ (36,276)	$ (1,970)	$ (3,721)	$ -	$ (172)	$ (1)	$ (42,140)
(19)	Expense Adjustments - Total	$ (62,554)	$ (1,836,664)	$ (100,293)	$ -	$ (172)	$ (1)	$ (1,999,685)
(20)	Total Cost of Service	$ 13,454,154	$ 20,100,844	$ 1,581,489	$ -	$ 143,521	$ 17,496	$ 35,297,503
(21)	Less: Misc Revenue - Energy	$ -	$ 119,983	$ -	$ -	$ -	$ -	$ 119,983
(22)	Less: Misc Revenue - Other	$ (4,869,165)	$ (264,378)	$ (499,478)	$ -	$ (23,104)	$ (138)	$ (5,656,263)
(23)	Less: Misc Revenue - Total	$ (4,869,165)	$ (144,395)	$ (499,478)	$ -	$ (23,104)	$ (138)	$ (5,536,280)
(24)	Net Cost of Service	$ 8,584,989	$ 19,956,450	$ 1,082,011	$ -	$ 120,417	$ 17,357	$ 29,761,223
(25)	Billing Units	1,268,834	523,880,472	1,268,834	1,268,834	132	132	
(26)	Unit Costs	6.766047479	0.038093517	0.852759969	0	912.25	131.49	$ 1,043.74

Customer Charge	$ 1,043.74
Energy Charge	0.03809
Demand Charge	7.62
Distribution Customer	1,043.74
Distribution Customer Margin	84.885
	$ 1,128.63

Louisville Gas and Electric Company

Unit Cost of Service Based on the Cost of Service Study
For the 12 Months Ended March 31, 2012

Rate CGS

		Customer Costs									
Description	**Reference**	**Customer-Related Low Pressure Mains Costs**	**Customer-Related High Pressure Main Costs**	**Customer-Related Direct Costs**	**Total Customer-Related Costs**	**Storage Demand-Related Costs**	**Storage Commodity Costs**	**Other Procurement Costs**	**Demand Related Low Pressure Mains Costs**	**Demand Related High Pressure Mains Costs**	**Total Costs**
(1) Rate Base	Conroy Exhibit C10 Page 2	$ 10,813,247	$ 709,321	$ 27,750,229	$ 39,272,796	$ 27,937,290	$ 306,982	$ 57,054	$ 20,113,706	$ 9,054,655	$ 96,742,484
(2) Rate Base Adjustments	Conroy Exhibit C10 Page 12	(34,268)	(2,248)	(87,943)	(124,459)	(88,536)	(973)	(181)	(63,742)	(28,695)	(306,585)
(3) Rate Base as Adjusted [(1) + (2)]	(1)+(2)	$ 10,778,979	$ 707,073	$ 27,662,286	$ 39,148,337	$ 27,848,754	$ 306,010	$ 56,874	$ 20,049,964	$ 9,025,960	$ 96,435,899
(4) Rate of Return	Proposed Class ROR	13.01%	13.01%	13.01%	13.01%	13.01%	13.01%	13.01%	13.01%	13.01%	13.01%
(5) Return [(3) x (4)]	(3) x (4)	$ 1,402,315	$ 91,988	$ 3,598,786	$ 5,093,089	$ 3,623,045	$ 39,811	$ 7,399	$ 2,608,444	$ 1,174,252	$ 12,546,040
(6) Interest Expenses	Conroy Exhibit C10 Page 10	$ 217,875	$ 14,292	$ 514,279	$ 746,446	$ 344,513	$ -	$ -	$ 405,270	$ 203,868	$ 1,700,097
(7) Net Income [(5) - (6)]	(5) - (6)	$ 1,184,440	$ 77,696	$ 3,084,507	$ 4,346,643	$ 3,278,532	$ 39,811	$ 7,399	$ 2,203,174	$ 970,384	$ 10,845,944
(8) Income Taxes	See Note Below	$ 795,189	$ 52,162	$ 2,070,824	$ 2,918,174	$ 2,201,085	$ 26,728	$ 4,967	$ 1,479,129	$ 651,480	$ 7,281,563
(9) Operation and Maintenance Expenses	Conroy Exhibit C10 Page 3	$ 1,012,788	$ 66,436	$ 3,666,838	$ 4,746,062	$ 1,154,732	$ 2,400,720	$ 446,188	$ 1,883,886	$ 1,903,379	$ 12,534,966
(10) Depreciation Expenses	Conroy Exhibit C10 Page 5	446,527	29,291	1,765,261	2,241,079	801,967	-	-	830,585	380,433	4,254,064
(11) Other Taxes	Conroy Exhibit C10 Page 9	153,354	10,060	361,981	525,395	242,490	-	-	285,254	143,495	1,196,634
(12) Other Expenses	Conroy Exhibit C10 Pages 6,7 & 8	(26,986)	(1,770)	(67,120)	(95,876)	(41,674)	-	-	(50,196)	(26,161)	(213,908)
(13) Expense Adjustments	Conroy Exhibit C10 Page 12	(30,668)	(2,012)	(111,035)	(143,715)	(34,966)	(72,696)	(13,511)	(57,046)	(57,636)	(379,569)
(14) Total Cost of Service [(4)+(8)+(9)+(10)+(11)+(12)+(13)]	(4)+(8)+(9)+(10)+(11)+(12)+(13)	$ 3,752,520	$ 246,155	$ 11,285,534	$ 15,284,209	$ 7,946,678	$ 2,394,563	$ 445,043	$ 6,980,056	$ 4,169,242	$ 37,219,791
(15) Less: Misc Revenue	Conroy Exhibit C10 Page 11	285,101	18,702	857,428	1,161,230	603,755	181,929	33,813	530,316	316,762	$ 2,827,804
(16) Net Cost of Service [(14) - (15)]	(13) - (14)	$ 3,467,419	$ 227,454	$ 10,428,106	$ 14,122,979	$ 7,342,922	$ 2,212,634	$ 411,231	$ 6,449,741	$ 3,852,480	$ 34,391,987
(17) Billing Units	Conroy Exhibit C10 Page 14	308,581	308,581	308,581	308,581	3,728,072	8,840,212	8,840,212	5,929,064	5,929,064	
(18) Unit Costs [(16) / (17)]	(15) / (16)	$11.24/Cust/Mo	$0.74/Cust/Mo	$33.79/Cust/Mo	$45.77/Cust/Mo	$1.9696/Mcf	$0.2503/Mcf	$0.0465/Mcf	$1.0878/Mcf	$0.6498/Mcf	

Louisville Gas and Electric Company

Unit Cost of Service Based on the Cost of Service Study
For the 12 Months Ended March 31, 2012

Rate IGS

		Customer Costs									
Description	**Reference**	**Customer-Related Low Pressure Mains Costs**	**Customer-Related High Pressure Main Costs**	**Customer-Related Direct Costs**	**Total Customer-Related Costs**	**Storage Demand-Related Costs**	**Storage Commodity Costs**	**Other Procurement Costs**	**Demand Related Low Pressure Mains Costs**	**Demand Related High Pressure Mains Costs**	**Total Costs**
(1) Rate Base	Conroy Exhibit C10 Page 2	$ 88,188	$ 5,867	$ 546,106	$ 640,160	$ 1,893,200	$ 24,223	$ 5,433	$ 1,246,811	$ 586,065	$ 4,395,892
(2) Rate Base Adjustments	Conroy Exhibit C10 Page 12	(255)	(17)	(1,576)	(1,848)	(5,464)	(70)	(16)	(3,599)	(1,692)	(12,688)
(3) Rate Base as Adjusted [(1) + (2)]	(1)+(2)	$ 87,933	$ 5,850	$ 544,530	$ 638,313	$ 1,887,736	$ 24,153	$ 5,417	$ 1,243,212	$ 584,373	$ 4,383,204
(4) Rate of Return	Proposed Class ROR	19.30%	19.30%	19.30%	19.30%	19.30%	19.30%	19.30%	19.30%	19.30%	19.30%
(5) Return [(3) x (4)]	(3) x (4)	$ 16,971	$ 1,129	$ 105,093	$ 123,192	$ 364,327	$ 4,662	$ 1,045	$ 239,936	$ 112,782	$ 845,945
(6) Interest Expenses	Conroy Exhibit C10 Page 10	$ 1,777	$ 118	$ 8,986	$ 10,881	$ 23,346	$ -	$ -	$ 25,122	$ 13,297	$ 72,646
(7) Net Income [(5) - (6)]	(5) - (6)	$ 15,194	$ 1,011	$ 96,107	$ 112,311	$ 340,981	$ 4,662	$ 1,045	$ 214,814	$ 99,486	$ 773,299
(8) Income Taxes	See Note Below	$ 10,277	$ 684	$ 65,006	$ 75,967	$ 230,638	$ 3,153	$ 707	$ 145,300	$ 67,292	$ 523,057
(9) Operation and Maintenance Expenses	Conroy Exhibit C10 Page 3	$ 8,260	$ 550	$ 51,440	$ 60,250	$ 78,252	$ 189,435	$ 42,486	$ 116,779	$ 124,257	$ 611,458
(10) Depreciation Expenses	Conroy Exhibit C10 Page 5	3,642	242	29,650	33,534	54,346	-	-	51,486	24,527	163,894
(11) Other Taxes	Conroy Exhibit C10 Page 9	1,251	83	6,325	7,659	16,433	-	-	17,682	9,359	51,133
(12) Other Expenses	Conroy Exhibit C10 Pages 6,7 & 8	(220)	(15)	(1,173)	(1,408)	(2,824)	-	-	(3,112)	(1,707)	(9,050)
(13) Expense Adjustments	Conroy Exhibit C10 Page 12	(573)	(38)	(3,570)	(4,181)	(5,431)	(13,147)	(2,949)	(8,105)	(8,624)	(42,436)
(14) Total Cost of Service [(4)+(8)+(9)+(10)+(11)+(12)+(13)]	(4)+(8)+(9)+(10)+(11)+(12)+(13)	$ 39,607	$ 2,635	$ 252,772	$ 295,013	$ 735,741	$ 184,103	$ 41,290	$ 559,967	$ 327,886	$ 2,144,000
(15) Less: Misc Revenue	Conroy Exhibit C10 Page 11	3,963	264	25,292	29,518	73,616	18,421	4,131	56,029	32,807	$ 214,523
(16) Net Cost of Service [(14) - (15)]	(13) - (14)	$ 35,644	$ 2,371	$ 227,480	$ 265,495	$ 662,125	$ 165,682	$ 37,159	$ 503,938	$ 295,079	$ 1,929,477
(17) Billing Units	Conroy Exhibit C10 Page 14	2,587	2,587	2,587	2,587	252,637	841,764	841,764	467,848	467,848	
(18) Unit Costs [(16) / (17)]	(15) / (16)	$13.78/Cust/Mo	$0.92/Cust/Mo	$87.93/Cust/Mo	$102.63/Cust/Mo	$2.6209/Mcf	$0.1968/Mcf	$0.0441/Mcf	$1.0771/Mcf	$0.6307/Mcf	

Louisville Gas and Electric Company

Unit Cost of Service Based on the Cost of Service Study
For the 12 Months Ended March 31, 2012

Rate AAGS

Description	Reference	Customer Costs: Customer-Related Low Pressure Mains Costs	Customer Costs: Customer-Related High Pressure Main Costs	Customer Costs: Customer-Related Direct Costs	Customer Costs: Total Customer-Related Costs	Storage Demand-Related Costs	Storage Commodity Costs	Other Procurement Costs	Demand Related Low Pressure Mains Costs	Demand Related High Pressure Mains Costs	Total Costs
(1) Rate Base	Conroy Exhibit C10 Page 2	$ 1,254	$ 384	$ 102,701	$ 104,338	$ -	$ -	$ 2,220	$ 336,455	$ 169,513	$ 612,526
(2) Rate Base Adjustments	Conroy Exhibit C10 Page 12	(4)	(1)	(340)	(345)	-	-	(7)	(1,113)	(561)	(2,026)
(3) Rate Base as Adjusted [(1) + (2)]	(1)+(2)	$ 1,250	$ 383	$ 102,361	$ 103,993	$ -	$ -	$ 2,213	$ 335,342	$ 168,952	$ 610,500
(4) Rate of Return	Proposed Class ROR	20.02%	20.02%	20.02%	20.02%	20.02%	20.02%	20.02%	20.02%	20.02%	20.02%
(5) Return [(3) x (4)]	(3) x (4)	$ 250	$ 77	$ 20,491	$ 20,817	$ -	$ -	$ 443	$ 67,129	$ 33,821	$ 122,210
(6) Interest Expenses	Conroy Exhibit C10 Page 10	$ 25	$ 8	$ 1,809	$ 1,842	$ -	$ -	$ -	$ 6,779	$ 3,193	$ 11,814
(7) Net Income [(5) - (6)]	(5) - (6)	$ 225	$ 69	$ 18,682	$ 18,976	$ -	$ -	$ 443	$ 60,350	$ 30,628	$ 110,396
(8) Income Taxes	See Note Below	$ 152	$ 47	$ 12,662	$ 12,861	$ -	$ -	$ 300	$ 40,902	$ 20,758	$ 74,820
(9) Operation and Maintenance Expenses	Conroy Exhibit C10 Page 3	$ 117	$ 36	$ 7,212	$ 7,366	$ -	$ -	$ 17,361	$ 31,513	$ 29,106	$ 85,345
(10) Depreciation Expenses	Conroy Exhibit C10 Page 5	52	16	6,098	6,165	-	-	-	13,894	7,717	27,776
(11) Other Taxes	Conroy Exhibit C10 Page 9	18	5	1,273	1,296	-	-	-	4,772	2,248	8,315
(12) Other Expenses	Conroy Exhibit C10 Pages 6,7 & 8	(3)	(1)	(236)	(240)	-	-	-	(840)	(406)	(1,486)
(13) Expense Adjustments	Conroy Exhibit C10 Page 12	(27)	(8)	(1,686)	(1,722)	-	-	(4,059)	(7,368)	(6,805)	(19,954)
(14) Total Cost of Service [(4)+(8)+(9)+(10)+(11)+(12)+(13)]	(4)+(8)+(9)+(10)+(11)+(12)+(13)	$ 559	$ 171	$ 45,813	$ 46,543	$ -	$ -	$ 14,045	$ 150,001	$ 86,438	$ 297,027
(15) Less: Misc Revenue	Conroy Exhibit C10 Page 11	111	34	9,134	9,279	-	-	2,800	29,906	17,234	$ 59,220
(16) Net Cost of Service [(14) - (15)]	(13) - (14)	$ 448	$ 137	$ 36,679	$ 37,263	$ -	$ -	$ 11,245	$ 120,095	$ 69,205	$ 237,807
(17) Billing Units	Conroy Exhibit C10 Page 14	164	164	164	164	-	343,961	343,961	184,636	184,636	
(18) Unit Costs [(16) / (17)]	(15) / (16)	$2.73/Cust/Mo	$0.84/Cust/Mo	$223.65/Cust/Mo	$227.22/Cust/Mo	#DIV/0!	$0.0000/Mcf	$0.0327/Mcf	$0.6504/Mcf	$0.3748/Mcf	

Louisville Gas and Electric Company

Unit Cost of Service Based on the Cost of Service Study
For the 12 Months Ended March 31, 2012

Rate FT

Description	Reference	Customer Costs: Customer-Related Low Pressure Mains Costs	Customer Costs: Customer-Related High Pressure Main Costs	Customer Costs: Customer-Related Direct Costs	Customer Costs: Total Customer-Related Costs	Storage Demand-Related Costs	Storage Commodity Costs	Other Procurement Costs	Demand Related Low Pressure Mains Costs	Demand Related High Pressure Mains Costs	Total Costs
(1) Rate Base	Conroy Exhibit C10 Page 2	$ 12,539	$ 2,084	$ 193,257	$ 207,879	$ -	$ -	$ 65,050	$ 1,386,172	$ 2,857,871	$ 4,516,972
(2) Rate Base Adjustments	Conroy Exhibit C10 Page 12	(53)	(9)	(821)	(884)	-	-	(277)	(5,892)	(12,148)	(19,200)
(3) Rate Base as Adjusted [(1) + (2)]	(1)+(2)	$ 12,485	$ 2,075	$ 192,435	$ 206,995	$ -	$ -	$ 64,774	$ 1,380,280	$ 2,845,723	$ 4,497,772
(4) Rate of Return	Proposed Class ROR	53.51%	53.51%	53.51%	53.51%	53.51%	53.51%	53.51%	53.51%	53.51%	53.51%
(5) Return [(3) x (4)]	(3) x (4)	$ 6,681	$ 1,110	$ 102,979	$ 110,770	$ -	$ -	$ 34,663	$ 738,634	$ 1,522,842	$ 2,406,908
(6) Interest Expenses	Conroy Exhibit C10 Page 10	$ 253	$ 42	$ 3,300	$ 3,595	$ -	$ -	$ -	$ 27,930	$ 53,835	$ 85,360
(7) Net Income [(5) - (6)]	(5) - (6)	$ 6,429	$ 1,068	$ 99,678	$ 107,175	$ -	$ -	$ 34,663	$ 710,704	$ 1,469,007	$ 2,321,548
(8) Income Taxes	See Note Below	$ 4,414	$ 734	$ 68,444	$ 73,591	$ -	$ -	$ 23,801	$ 488,002	$ 1,008,686	$ 1,594,080
(9) Operation and Maintenance Expenses	Conroy Exhibit C10 Page 3	$ 1,174	$ 195	$ 166,074	$ 167,444	$ -	$ -	$ 508,717	$ 129,831	$ 490,712	$ 1,296,704
(10) Depreciation Expenses	Conroy Exhibit C10 Page 5	518	86	11,386	11,989	-	-	-	57,241	130,104	199,335
(11) Other Taxes	Conroy Exhibit C10 Page 9	178	30	2,323	2,530	-	-	-	19,659	37,892	60,081
(12) Other Expenses	Conroy Exhibit C10 Pages 6,7 & 8	(31)	(5)	(431)	(467)	-	-	-	(3,459)	(6,849)	(10,775)
(13) Expense Adjustments	Conroy Exhibit C10 Page 12	(4)	(1)	(562)	(567)	-	-	(1,722)	(439)	(1,661)	(4,389)
(14) Total Cost of Service [(4)+(8)+(9)+(10)+(11)+(12)+(13)]	(4)+(8)+(9)+(10)+(11)+(12)+(13)	$ 12,930	$ 2,149	$ 350,212	$ 365,291	$ -	$ -	$ 565,458	$ 1,429,468	$ 3,181,727	$ 5,541,945
(15) Less: Misc Revenue	Conroy Exhibit C10 Page 11	346	58	9,378	9,782	-	-	15,142	38,279	85,203	$ 148,407
(16) Net Cost of Service [(14) - (15)]	(13) - (14)	$ 12,584	$ 2,091	$ 340,834	$ 355,509	$ -	$ -	$ 550,316	$ 1,391,189	$ 3,096,525	$ 5,393,538
(17) Billing Units	Conroy Exhibit C10 Page 14	876	876	876	876	-	10,079,083	10,079,083	3,782,264	3,782,264	
(18) Unit Costs [(16) / (17)]	(15) / (16)	$14.37/Cust/Mo	$2.39/Cust/Mo	$389.08/Cust/Mo	$405.83/Cust/Mo	#DIV/0!	$0.0000/Mcf	$0.0546/Mcf	$0.3678/Mcf	$0.8187/Mcf	

LOUISVILLE GAS AND ELECTRIC COMPANY

CASE NO. 2012-00222

Response to Commission Staff's Third Request for Information
Dated August 28, 2012

Question No. 8

Responding Witness: Robert M. Conroy

Q-8. Refer to the application, Conroy Exhibit M2. Pages 1 and 2 state that the source of the referenced costs is Exhibit Conroy C3. Provide the location in Exhibit Conroy C3 of each of the costs shown on these pages.

A-8. In preparing this response, LG&E determined that Conroy Exhibit M2 as originally filed had not been updated to reflect the final cost of service results. LG&E provided an electronic version of Conroy Exhibit M2 in "Att-PSC2-108-File13" ('M-2 LGE Redundant Capacity Conroy Exhibit.xlsx'). LG&E is providing in Excel format an updated spreadsheet ('M-2 LGE Redundant Capacity Conroy Exhibit Revised.xlsx'). See Attachment 1 for an updated Conroy Exhibit M2.

All amounts on Conroy Exhibit M2 referenced to Conroy Exhibit C3 are either taken directly from Conroy Exhibit C3, or are the result of mathematical operations using amounts directly from Conroy Exhibit C3. See Attachment 2 for a line–by–line link between the amounts on Conroy Exhibit M2 and Conroy Exhibit C3.

One attachment is being provided in a separate file in Excel format.

Louisville Gas and Electric Company
Redundant Capacity Charge Cost Support
Derivation of Distribution Demand-Related Cost
Twelve Months Ended March 31, 2012

Revised Cells Highlighted

Secondary Service

Distribution Demand Costs				
	PSS	$ 4,000,984		
	TODS	829,396		
	Total Cost	$ 4,830,380		
Billing Demand				
	PS	6,013,535		
	TODS	1,197,033		
	Total Cost	7,210,568		
Unit Cost			$ 0.67	
Rate Base				
	PS	$ 35,108,562		
	TODS	8,697,554		
	Total Cost	$ 43,806,116		
Return		$ 3,587,721		
Unit Return			$ 0.50	
Capacity Charge			$ 1.17	/ KW

Source: Electric Cost of Service Study, Conroy Exhibit C3

Louisville Gas and Electric Company
Redundant Capacity Charge Cost Support
Derivation of Distribution Demand-Related Cost
Twelve Months Ended March 31, 2012

Primary Service

Distribution Demand Costs				
PSP	$	223,019		
TODP		2,171,427		
Total Cost	$	2,394,446		
Billing Demand				
PSP		652,713		
TODP		4,460,699		
Total Cost		5,113,412		
Unit Cost			$	0.47
Rate Base				
PSP	$	2,159,870		
TODP		20,225,825		
Total Cost	$	22,385,695		
Return	$	1,833,388		
Unit Return			$	0.36
Capacity Charge			$	0.83 / KW

Source: Electric Cost of Service Study, Conroy Exhibit C3

LG&E Exhibit M2,page 2 of 4, Tied to Cost of Service C3 — Primary Distribution Unit Demand Costs

Note: Purple highlighted cells are on Conroy Exhibit M2
Blue highlighted cells are inputs from Conroy Exhibit C3
all other cells are calculated

		A	B	C	
		Col. (A) = Col. (B) + Col. (C) Distribution Primary	Rate PS-P	Rate TODP	
1	Distribution Demand Costs -- Exhibit M2	$ 2,394,446	$ 223,019	$ 2,171,427	Sum of Ls.3 through 11
2	Net Income	$ 1,504,511	$ 229,135	$ 1,275,376	L.58 - L.62
3	Income Taxes	$ 927,620	$ 150,528	$ 777,092	L.18
4	Operation and Maintenance Expenses	2,850,899	275,129	2,575,770	C3, page 7, Distribution Substation general, Lines pri & sec demand, line transformers dem
5	Depreciation Expenses	1,060,822	102,376	958,446	C3, page 11, Distribution Substation general, Lines pri & sec demand, line transformers de
6	Other Expenses	209,584	20,226	189,358	Sum of individual components 6a through 6e
a	Regulatory Credits	(1,584)	(153)	(1,431)	C3, page 13, Distribution Substation general, Lines pri & sec demand, line transformers de
b	Accretion Expense	1,265	122	1,143	C3, page 15, Distribution Substation general, Lines pri & sec demand, line transformers de
c	Property and Other Taxes	238,918	23,057	215,861	C3, page 17, Distribution Substation general, Lines pri & sec demand, line transformers de
d	Amortization of ITC	(29,008)	(2,799)	(26,209)	C3, page 19, Distribution Substation general, Lines pri & sec demand, line transformers de
e	Other Expenses	(8)	(1)	(7)	C3, page 21, Distribution Substation general, Lines pri & sec demand, line transformers de
7	Other Depreciation Expenses	74,484	7,223	67,261	L.20
8	Curtailable Service Credit	-	-	-	Assigned 100% to production
9	Expense Adjustments - Distribution	(356,609)	(96,412)	(260,197)	L.41
10	Expense Adjustments	(13,175)	(14,421)	1,246	L.40
11	Miscellaneous Revenue - Other (enter as negative)	$ (2,359,179)	$ (221,630)	$ (2,137,550)	L.53 ÷ L.43 x L.69
12	Total net income for rate schedule		$ 3,153,491	$ 16,049,123	C3, p. 35, Net Operating Income, Pro-Forma
13	Less interest expense		$ 474,301	$ 3,674,103	C3, p27, Interest Expense
14	Net income less interest		$ 2,679,190	$ 12,375,020	L.12 - L.13
	Income taxes allocated to demand based on net income:				
15	Income taxes -- actual		$ 1,748,872	$ 4,469,277	C3, p.31, Sate and Federal Income Taxes
16	Incremental income taxes		$ 11,201	$ 3,070,871	C3, p. 35, Incremental income taxes
17	Total Income Taxes		$ 1,760,073	$ 7,540,148	L.15 + L.16
18	Distribution Demand component of income taxes		$ 150,528	$ 777,091.54	L.14 ÷ L.2 x L.17

LG&E Exhibit M2,page 2 of 4, Tied to Cost of Service C3 — Primary Distribution Unit Demand Costs

Note: Purple highlighted cells are on Conroy Exhibit M2
Blue highlighted cells are inputs from Conroy Exhibit C3
all other cells are calculated

		A	B	C	
		Col. (A) = Col. (B) + Col. (C)			
	Other Depreciation Expense -- allocate on rate base				
19	Amortization Expense		$ 84,451	$ 652,640	C3, p25
20	Amortization Expense allocated to distribution demand		$ 7,223	$ 67,261	L.53 ÷ L.43 x L.20
			Expense Adjustments from Unit Cost schedules		
		Total Primary	Rate PS-P	Rate TOD-P	
19	Expense Adjustments assigned to Distribution				
20	Eliminate DSM Expenses (allocate to demand & customer)	$ (286,532)	$ (98,989)	$ (187,543)	C3, page 29 PS-P and TOD-P
21	Normalized storm damage expenses (allocate to demand & customer)	(84,393)	(8,239)	(76,154)	C3, page 29 PS-P and TOD-P
22	Year end adjustment	$ 294	$ 140	$ 155	C3, page 29 PS-P and TOD-P
23	Annualized depreciation expenses under current rates	86,651	9,928	76,723	C3, page 29 PS-P and TOD-P
24	Labor adjustment	406,224	46,918	359,306	C3, page 29 PS-P and TOD-P
25	Pension & post retirement expense adjustment	(446,820)	(51,607)	(395,214)	C3, page 29 PS-P and TOD-P
26	Property insurance expense adjustment	28,523	3,257	25,265	C3, page 29 PS-P and TOD-P
27	Eliminate advertising expenses	(77,103)	(10,343)	(66,760)	C3, page 29 PS-P and TOD-P
28	Remove out of period items	110,706	12,625	98,082	C3, page 29 PS-P and TOD-P
29	Amortization of rate case expenses	(7,348)	(820)	(6,527)	C3, page 29 PS-P and TOD-P
30	Adjustment for Swap termination regulatory asset	11,928	1,362	10,566	C3, page 29 PS-P and TOD-P
31	2011 Wind Storm regulatory asset amortization	188,737	21,523	167,214	C3, page 29 PS-P and TOD-P
32	Adjustment for injuries and damages FERC account 925	(43,970)	(5,021)	(38,948)	C3, page 29 PS-P and TOD-P
33	General Management Audit regulatory asset amortization	3,540	404	3,136	C3, page 29 PS-P and TOD-P
34	Federal & State Income Tax Adjustment	(376,257)	(180,611)	(195,646)	C3, page 29 PS-P and TOD-P
35	Federal & State Income Tax Interest Adjustment	3,389	953	2,436	C3, page 29 PS-P and TOD-P
36	Prior income tax true-ups & adjustments	(72,963)	(20,521)	(52,442)	C3, page 29 PS-P and TOD-P
37	Adjustment for tax basis depreciation reduction	(9,902)	(1,131)	(8,772)	C3, page 29 PS-P and TOD-P
38	Adjustment ofr amortization of investment tax credit	37,843	4,322	33,521	C3, page 29 PS-P and TOD-P
39	Total of Other Expense Adjustments	$ (527,453)	$ (168,622)	$ 12,094	Sum of Ls.22 - 38
40	Total Primary portion of other expense adj	$ (13,175)	$ (14,421)	$ 1,246	L.53 ÷ L.43 x L.39
41	Total Primary portion of distribution exp adj	$ (356,609)	$ (96,412)	$ (260,197)	(L.20 + L.21) x (L.53÷ (L.53 + L.54))
42	Total Primary expense adjustments	$ (369,783)	$ (110,833)	$ (258,950)	Sum of Ls.40 - 41

LG&E Exhibit M2,page 2 of 4, Tied to Cost of Service C3 — Primary Distribution Unit Demand Costs

Note: Purple highlighted cells are on Conroy Exhibit M2
Blue highlighted cells are inputs from Conroy Exhibit C3
all other cells are calculated

		A	B	C	
		Col. (A) = Col. (B) + Col. (C)			
		Total System Rate Base, C3 page 5	Rate PS-P	Rate TODP	
43	Rate Base	$ 1,920,997,668	$ 25,673,931	$ 199,460,877	C3, pp 5, PS-P and TOD-P total rate base
44	Rate Base Adjustments:	C3, page 29 Total System			
45	ECR Plan Eliminations	(183,667,066)	(339,663)	(2,605,171)	C3, page 29 PS-P and TOD-P
46	Adjustmentto Reflect Depreciation Reserve	(712,846)	(9,928)	(76,723)	C3, page 29 PS-P and TOD-P
47	Cash Working Capital	(5,709,964)	(69,742)	(527,047)	C3, page 29 PS-P and TOD-P
48	Total Rate Base Adjustments	(190,089,876)	(419,332)	(3,208,942)	Sum of Ls.45 - 47
49	Adjusted Net Rate Base	$ 1,730,907,792	$ 25,254,598	$ 196,251,936	L.43 + L.48
50	Allocate Rate Base Adjustments between Substation Demand and Lines Demand:		Rate PS-P	Rate TODP	
51	Substation Demand Rate Base		$ 863,599	$ 8,085,052	C3, p 5, PS-P and TOD-P Distribution Substation
52	Primary Lines Demand Rate Base		1,332,133	12,471,488	C3, p 5, PS-P and TOD-P Distribution Lines
53	Total Primary Demand Rate Base		$ 2,195,733	$ 20,556,540	Sum of Ls.51 - 52
54	Primary Customer Rate Base		246,322	276,576	C3, p 5 PS-P and TOD-P, Primary Customer Lines and Meters
55	Rate Base Adjustments allocated to Distribution Demand, using total Rate Base		(35,863)	(330,715)	L.53, Col. B or C ÷ L.43, Col.B or C x L.48, Col.B or C
56	Primary Demand Only Adjusted Rate Base, Exhibit M2		$ 2,159,870	$ 20,225,825	L.53 + L.55
57	Cost of Service Proposed Rate of Return		12.49%	8.18%	C3, p35 Rate of Return
58	Primary Demand Return on Rate Base		$ 269,699	$ 1,654,031	L.56 x L.57
	Allocate Interest Expense based on unadjdusted rate base:				
59	Rate Base		$ 25,673,931	$ 199,460,877	L. 43 above
60	Primary Demand only Rate Base		$ 2,195,733	$ 20,556,540	L. 53 above
61	Interest Expense		$ 474,301	$ 3,674,103	C3, p27, Interest Expense
62	Interest Expense allocated to distribution demand		$ 40,564	$ 378,655	L.60, Col. B or C ÷ L.59, Col.B or C x L.61, Col.B or C
	Allocate Miscellaneous Revenue based on rate base				
63	Intercompany sales		$ 1,571,511	$ 12,685,829	C3, p25
64	Off-system sales		$ 880,360	$ 6,982,573	C3, p25
65	Forfeited discounts		$ 10,700	$ 71,158	C3, p25
66	Misc service revenues		$ -	$ -	C3, p25
67	Rent from electric property		$ 39,538	$ 307,172	C3, p25
68	Other electric revenue		$ 89,328	$ 693,993	C3, p25
69	Total miscellaneous revenue to allocate		$ 2,591,437	$ 20,740,725	Sum of Ls.63 through 68

LG&E Exhibit M2,p.2 of 2, Tied to Cost of Service C3 — Secondary Distribution Unit Demand Costs

Note:		Purple highlighted cells are on Revised Conroy Exhibit M2				
1		Distribution Demand Costs -- Exhibit M2	$ 4,830,379	$ 4,000,984	$ 829,396	Sum of Ls.3 through 11
2		Net Income	$ 4,381,627	$ 3,722,996	$ 658,631	L.60 - L.64
3		Income Taxes	$ 2,608,257	$ 2,335,808	$ 272,449	L.18
4		Operation and Maintenance Expenses	4,895,118	3,932,002	963,116	C3, p.7, Distribution Substation general, Lines pri & sec demand, line transformers demand
5		Depreciation Expenses	2,079,056	1,666,186	412,870	C3, p.11, Distribution Substation general, Lines pri & sec demand, line transformers demand
6		Other Taxes	410,754	329,184	81,570	Sum of individual components 6a through 6e
	a	Regulatory Credits	(3,104)	(2,488)	(616)	C3, p.13, Distribution Substation general, Lines pri & sec demand, line transformers demand
	b	Accretion Expense	2,479	1,987	492	C3, p.15, Distribution Substation general, Lines pri & sec demand, line transformers demand
	c	Property and Other Taxes	468,245	375,258	92,987	C3, p.17, Distribution Substation general, Lines pri & sec demand, line transformers demand
	d	Amortization of ITC	(56,852)	(45,562)	(11,290)	C3, p.19, Distribution Substation general, Lines pri & sec demand, line transformers demand
	e	Other Expenses	(15)	(12)	(3)	C3, p.21, Distribution Substation general, Lines pri & sec demand, line transformers demand
7		Other depreciation Expenses	145,235	116,340	28,895	L.20
8		Curtailable Service Credit	-	-	-	Assigned 100% to production
9		Expense Adjustments - Distribution	(1,289,612)	(1,048,107)	(241,505)	L.41
10		Expense Adjustments	18,804	(110,618)	129,423	L.40
11		Miscellaneous Revenue - Other (enter as negative)	$ (4,037,233)	$ (3,219,812)	$ (817,422)	L.55 ÷ L.43 x L.71
12		Total net income for rate schedule		$ 36,347,578	$ 6,839,037	C3, p.35, Net Operating Income, pro-Forma
13		Less interest Expense		$ 5,468,005	$ 1,359,312	L. 63
14		Net income less interest		$ 30,879,573	$ 5,479,725	L.12 - L.13
		Income taxes allocated to demand based on net income:				
15		Income taxes -- actual		$ 16,094,394	$ 1,281,412	C3, p.31, Sate and Federal Income Taxes
16		Incremental income taxes		$ 3,279,454	$ 985,330	C3, p.35, Incremental income taxes
17		Total Income Taxes		$ 19,373,848	$ 2,266,742	L.15 + L.16
18		Distribution Demand component of income taxes		$ 2,335,808	$ 272,449.30	L.14 ÷ L.2 x L.17
		Other Depreciation Expense -- allocate on rate base				
19		Amortization Expense		$ 964,959	$ 240,399	C3, p.25
20		Amortization Expense allocated to distribution demand		$ 116,340	$ 28,895	L.55 ÷ L.43 x L.20

LG&E Exhibit M2,p.2 of 2, Tied to Cost of Service C3 — Secondary Distribution Unit Demand Costs

Note: Purple highlighted cells are on Revised Conroy Exhibit M2

			Expense Adjustments from Unit Cost schedules		
		Total Secondary	Rate p.S	Rate TODp.	
19	Expense Adjustments assigned to Distribution				
20	Eliminate DSM expenses (allocate to demand & customer)	$ (1,221,250)	$ (1,007,437)	$ (213,813)	C3, p.31 PS-S and TOD-S
21	Normalized storm damage expenses (allocate to demand & customer)	(173,403)	(140,176)	(33,227)	C3, p.31 PS-S and TOD-S
22	Year end adjustment	5,027	4,769	258	C3, p.31 PS-S and TOD-S
23	Annualized depreciation expenses under current rates	141,699	113,438	28,261	C3, p.31 PS-S and TOD-S
24	Labor adjustment	636,352	509,804	126,548	C3, p.31 PS-S and TOD-S
25	Pension & post retirement expense adjustment	(699,945)	(560,751)	(139,194)	C3, p.31 PS-S and TOD-S
26	Property insurance expense adjustment	47,099	37,730	9,369	C3, p.31 PS-S and TOD-S
27	Eliminate advertising expenses	(128,181)	(105,888)	(22,293)	C3, p.31 PS-S and TOD-S
28	Remove out of period items	181,656	145,497	36,159	C3, p.31 PS-S and TOD-S
29	Amortization of rate case expenses	(10,686)	(8,524)	(2,162)	C3, p.31 PS-S and TOD-S
30	Adjustment for swap termination regulatory asset	19,696	15,778	3,918	C3, p.31 PS-S and TOD-S
31	2011 Wind Storm regulatory asset amortization	309,695	248,049	61,646	C3, p.31 PS-S and TOD-S
32	Adjustment for injuries and damages FERC account 925	(72,606)	(58,163)	(14,443)	C3, p.31 PS-S and TOD-S
33	General Management Audit regulatory asset amortization	5,846	4,683	1,163	C3, p.31 PS-S and TOD-S
34	Federal & State Income Tax Adjustment	(128,092)	(1,120,802)	992,710	C3, p.31 PS-S and TOD-S
35	Federal & State Income Tax Interest Adjustment	9,470	8,772	698	C3, p.31 PS-S and TOD-S
36	Prior income tax true-ups & adjustments	(203,886)	(188,850)	(15,036)	C3, p.31 PS-S and TOD-S
37	Adjustment for tax basis depreciation reduction	(16,352)	(13,099)	(3,253)	C3, p.31 PS-S and TOD-S
38	Adjustment for amortization of investment tax credit	62,489	50,059	12,430	C3, p.31 PS-S and TOD-S
39	Total of Other Expense Adjustments	$ (1,235,373)	$ (917,499)	$ 1,076,779	Sum of Ls.22 - 38
40	Total Secondary portion of other expense adj	$ 18,804	$ (110,618)	$ 129,423	L.55 ÷ L.43 x L.39
41	Total Secondary portion of distribution exp. adj	$ (1,289,612)	$ (1,048,107)	$ (241,505)	(L.20 + L.21) x (L.55÷ (L.55 + L.56))
42	Total Secondary expense adjustments	$ (1,270,808)	$ (1,158,725)	$ (112,082)	Sum of Ls.40 - 41

		Total System Rate Base, C3 p.5	Rate PS-S	Rate TOD-S	
43	Rate Base	$ 1,920,997,668	$ 295,884,998	$ 73,533,945	C3, p. 5, PS-S and TOD-S total rate base
44	Rate Base Adjustments:	C3, p.33 Total System			
45	ECR plan eliminations	(20,091,143)	(3,770,825)	(946,072)	C3, p.33 PS-S and TOD-S
46	Adjustment to reflect depreciation reserve	(696,536)	(113,438)	(28,261)	C3, p.33 PS-S and TOD-S
47	Cash working capital	(5,766,234)	(800,464)	(197,117)	C3, p.33 PS-S and TOD-S
48	Total Rate Base Adjustments	(26,553,913)	(4,684,727)	(1,171,450)	Sum of Ls.45 - 47
49	Adjusted Net Rate Base	$ 1,894,443,755	$ 291,200,271	$ 72,362,496	L.43 + L.48

LG&E Exhibit M2,p.2 of 2, Tied to Cost of Service C3 — Secondary Distribution Unit Demand Costs

Note: Purple highlighted cells are on Revised Conroy Exhibit M2

		Rate PS-S	Rate TOD-S	
50	Allocate Rate Base Adjustments between Substation Demand and Lines Demand:			
51	Substation Demand Rate Base	$ 10,103,322	$ 2,422,372	C3, p. 5, PS-S and TOD-S Distribution Substation
52	primary Lines Demand Rate Base	15,584,744	3,736,598	C3, p. 5, PS-S and TOD-S Distribution Lines - primary demand
53	Secondary Lines Demand Rate Base	4,163,561	1,117,220	C3, p. 5, PS-S and TOD-S Distribution Lines - primary demand
54	Distribution Lines Transformers Rate Base	5,821,749	1,562,166	C3, p. 5, PS-S and TOD-S Lines Transformers - Demand
55	Total Secondary Demand Rate Base	$ 35,673,376	$ 8,838,355	Sum of Ls.51 - 54
56	Secondary Customer Rate Base	3,386,777	202,565	C3, p. 5 PS-S and TOD-S, Lines, Transformers, Services and Meters
57	Rate Base Adjustments allocated to Distribution Demand, using total Rate Base	(564,814)	(140,801)	L.55 ÷ L.43 x L.48
58	Secondary Demand Only Adjusted Rate Base, Exhibit M2	$ 35,108,562	$ 8,697,554	L.55 + L.57
59	Cost of Service proposed Rate of Return	12.48%	9.45%	C3, p.35 Rate of Return
60	Secondary Demand Return on Rate Base	$ 4,382,246	$ 822,013	L.58 x L.59
	Allocate Interest Expense based on unadjdusted rate base:			
61	Rate Base	$ 295,884,998	$ 73,533,945	L. 43 above
62	Secondary demand only rate rase	$ 35,673,376	$ 8,838,355	L. 55 above
63	Interest expense	$ 5,468,005	$ 1,359,312	C3, p.27, Interest Expense
64	Interest expense allocated to distribution demand	$ 659,250	$ 163,381	L.62 ÷ L.61 x L.63
	Allocate Miscellaneous Revenue based on rate base			
65	Intercompany sales	$ 15,838,927	$ 4,056,354	C3, p.25
66	Off-system sales	$ 9,188,146	$ 2,335,272	C3, p.25
67	Forfeited discounts	$ 193,798	$ 40,121	C3, p.25
68	Misc service revenues	$ -	$ -	C3, p.25
69	Rent from electric property	$ 455,666	$ 113,243	C3, p.25
70	Other electric revenue	$ 1,029,486	$ 255,850	C3, p.25
71	Total miscellaneous revenue to allocate	$ 26,706,023	$ 6,800,840	Sum of Ls.65 through 70

LOUISVILLE GAS AND ELECTRIC COMPANY

CASE NO. 2012-00222

Response to Commission Staff's Third Request for Information
Dated August 28, 2012

Question No. 9

Responding Witness: Robert M. Conroy

Q-9. Refer to the application, Conroy Exhibit M3, pages 1-3. For the amounts referenced to Exhibit Conroy C3, provide their location in that exhibit.

A-9. When preparing the requested information, LG&E found some minor mathematical errors that changed the final calculation for Secondary demand costs. LG&E provided an electronic version of Conroy Exhibit M3 in "Att-PSC2-108-File14" ('M-3 LGE Standby Rate Final.xlsx'). LG&E is providing in Excel format an updated spreadsheet ('M-3 LGE Standby Rate Final Revised.xlsx'). See Attachment 1 for a revised Conroy Exhibit M3.

All amounts on Conroy Exhibit M3 that are referenced to Conroy Exhibit C3 are either taken directly from Conroy Exhibit C3, or are the result of mathematical operations using amounts directly from Conroy Exhibit C3. See Attachment 2 for a line–by–line link between the amounts on revised Conroy Exhibit M3 and Conroy Exhibit C4.

One attachment is being provided in a separate file in Excel format.

Louisville Gas and Electric Company
Supplemental / Standby Rate Cost Support

Production and Transmission Unit Demand Costs
Total System

	Reference	**Total Production Cost**	**Total Transmission Cost**	**Total**
Operation and Maintenance Expenses	Conroy Exhibit C3	$ 121,412,889	$ 21,937,346	$ 143,350,235
Depreciation Expenses	Conroy Exhibit C3	89,841,242	6,282,596	$ 96,123,838
Accretion Expenses	Conroy Exhibit C3	1,616,361	4,325	$ 1,620,686
Property Taxes	Conroy Exhibit C3	14,538,440	1,561,012	$ 16,099,452
Other Expenses	Conroy Exhibit C3	(460)	(49)	$ (509)
Regulatory Credits	Conroy Exhibit C3	(3,812,290)	(7,280)	$ (3,819,570)
Amortization Expense	Conroy Exhibit C3	3,659,449	375,386	$ 4,034,834
Amortization of ITC	Conroy Exhibit C3	(1,765,173)	(189,529)	$ (1,954,702)
Expense Adjustments	Conroy Exhibit C3	(1,405,740)	(2,610,821)	$ (4,016,562)
Sub-Total Expenses		$ 224,084,717	$ 27,352,984	$ 251,437,702
Adjusted Rate Base	Conroy Exhibit C3	1,170,051,684	120,023,671	1,290,075,355
Return	Rate Base x Weighted Cost of Capital %	91,231,364	9,358,495	100,589,859
Income Taxes	Rate Base x Income Tax %	42,724,607	4,382,682	47,107,288
Total Revenue Requirement	Expenses + Return + Income Taxes	$ 358,040,688	$ 41,094,161	$ 399,134,849
100% Load Factor Demand	System CP x 12 months @ 90% PF	35,375,107	35,375,107	35,375,107
Unit Cost	Total Revenue Requirement / Demand	$ 10.12	$ 1.16	$ 11.28

			Weighted Cost of Capital	Income Taxes	Weighted Cost of Capital Grossed Up For Inc Taxes
Short Term Debt	0.00%	0.41%	0.00%		0.00%
Long Term Debt	44.36%	3.78%	1.68%		1.68%
Common Equity	55.64%	11.00%	6.12%	3.65%	9.77%
Total Capitalization	100.00%		7.80%		11.45%
Composite State and Fed Inc Tax Rate	37.3674%				

Louisville Gas and Electric Company
Supplemental / Standby Rate Cost Support

Primary Distribution Unit Demand Costs
Power Service Primary & TOD Primary

	Reference	Distribution Primary Substation Cost	Distribution Primary Lines Cost	Distribution Primary Transformer Cost	Total
Operation and Maintenance Expenses	Conroy Exhibit C3	$ 918,722	$ 1,932,177	$ -	$ 2,850,899
Depreciation Expenses	Conroy Exhibit C3	$ 417,680	$ 643,142	$ -	$ 1,060,822
Accretion Expenses	Conroy Exhibit C3	$ 498	$ 767	$ -	$ 1,265
Property Taxes	Conroy Exhibit C3	$ 94,070	$ 144,849	$ -	$ 238,919
Other Expenses	Conroy Exhibit C3	$ (3)	$ (4)	$ -	$ (8)
Regulatory Credits	Conroy Exhibit C3	$ (623)	$ (961)	$ -	$ (1,584)
Amortization Expense	Conroy Exhibit C3	$ 29,295	$ 45,189	$ -	$ 74,484
Amortization of ITC	Conroy Exhibit C3	$ (11,421)	$ (17,586)	$ -	$ (29,007)
Expense Adjustments	Conroy Exhibit C3	$ (119,166)	$ (250,619)	$ -	$ (369,785)
Sub-Total Expenses		$ 1,329,051	$ 2,496,954	$ -	$ 3,826,005
Adjusted Rate Base	Conroy Exhibit C3	8,804,473	13,581,221	-	22,385,694
Return	Rate Base x Weighted Cost of Capital %	686,503	1,058,956	-	1,745,459
Income Taxes	Rate Base x Income Tax %	321,497	495,920	-	817,417
Total Revenue Requirement	Expenses + Return + Income Taxes	$ 2,337,051	$ 4,051,830	$ -	$ 6,388,881
Billing Demand	Billing Demand @ 90% PF	5,234,410	5,234,410	5,234,410	5,234,410
Unit Cost	Total Revenue Requirement / Demand	$ 0.4465	$ 0.7741	$ -	$ 1.2206

			Weighted Cost of Capital	Income Taxes	Weighted Cost of Capital Grossed Up For Inc Taxes
Short Term Debt	0.00%	0.41%	0.00%		0.00%
Long Term Debt	44.36%	3.78%	1.68%		1.68%
Common Equity	55.64%	11.00%	6.12%	3.65%	9.77%
Total Capitalization	100.00%		7.80%		11.45%
Composite State and Fed Inc Tax Rate	37.3674%				

Louisville Gas and Electric Company
Supplemental / Standby Rate Cost Support

Secondary Distribution Unit Demand Costs
Power Service Secondary & TOD Secondary

Revisions Highlighted

	Reference	Distribution Secondary Substation Cost	Distribution Secondary Lines Cost	Distribution Secondary Transformer Cost	Total
Operation and Maintenance Expenses	Conroy Exhibit C3	$ 1,285,962	$ 739,183	$ 165,446	$ 2,190,591
Depreciation Expenses	Conroy Exhibit C3	$ 584,640	$ 246,044	$ 348,148	$ 1,178,831
Accretion Expenses	Conroy Exhibit C3	$ 697	$ 293	$ 415	$ 1,406
Property Taxes	Conroy Exhibit C3	$ 131,672	$ 55,414	$ 78,410	$ 265,496
Other Expenses	Conroy Exhibit C3	$ (4)	$ (2)	$ (3)	$ (9)
Regulatory Credits	Conroy Exhibit C3	$ (873)	$ (367)	$ (300)	$ (1,541)
Amortization Expense	Conroy Exhibit C3	$ 40,869	$ 17,231	$ 24,093	$ 82,193
Amortization of ITC	Conroy Exhibit C3	$ (15,987)	$ (6,728)	$ (9,520)	$ (32,235)
Expense Adjustments	Conroy Exhibit C3	$ (749,943)	$ (425,604)	$ (95,260)	$ (1,270,807)
Sub-Total Expenses		$ 1,277,032	$ 625,464	$ 511,429	$ 2,413,925
Adjusted Rate Base	Conroy Exhibit C3	12,174,774	5,132,884	7,177,116	24,484,774
Return	Rate Base x Weighted Cost of Capital %	949,292	400,222	559,615	1,909,129
Income Taxes	Rate Base x Income Tax %	444,564	187,428	262,073	894,065
Total Revenue Requirement	Expenses + Return + Income Taxes	$ 2,670,888	$ 1,213,113	$ 1,333,117	$ 5,217,119
Billing Demand	Billing Demand @ 90% PF	8,097,988	8,097,988	8,097,988	8,097,988
Unit Cost	Total Revenue Requirement / Demand	$ 0.3298	$ 0.1498	$ 0.1646	$ 0.6442

			Weighted Cost of Capital	Income Taxes	Weighted Cost of Capital Grossed Up For Inc Taxes
Short Term Debt	0.00%	0.41%	0.00%		0.00%
Long Term Debt	44.36%	3.78%	1.68%		1.68%
Common Equity	55.64%	11.00%	6.12%	3.65%	9.77%
Total Capitalization	100.00%		7.80%		11.45%

Composite State and Fed Inc Tax Rate 37.3674%

Louisville Gas and Electric Company
Supplemental / Standby Rate Cost Support

Calculation of LG&E 100% Load Factor Demand

LG&E System Peak	(1) * 12
(1)	(2)
2,653,133	31,837,596

90% Power Factor Adjustment	(6) / (7)
(7)	(8)
90%	35,375,107

100% Load Factor Demand
35,375,107

LG&E Exhibit M3 Revised, page 1 of 4, Tied to Cost of Service C3 — Production and Transmission Unit Demand Costs

Total Production Cost and Total Transmission Cost tie to Revised Exhibit M3, page 1 of 4

Blue highlighted cells are inputs from Conroy Exhibit C3

		Total Production Cost	
1	Operation and Maintenance Expenses	$ 121,412,889	C3, page 7, Total System Production Demand Base, Intermediate, Peak
2	Depreciation Expenses	89,841,242	C3, page 11, Total System Production Demand Base, Intermediate, Peak
3	Accretion Expenses	1,616,361	C3, page 15, Total System Production Demand Base, Intermediate, Peak
4	Property Taxes	14,538,440	C3, page 17, Total System Production Demand Base, Intermediate, Peak
5	Other Expenses	(460)	C3, page 21, Total System Production Demand Base, Intermediate, Peak
6	Regulatory Credits	(3,812,290)	C3, page 13, Total System Production Demand Base, Intermediate, Peak
7	Amortization Expense	3,659,449	L. 23, Production Demand
8	Amortization of ITC	(1,765,173)	C3, page 19, Total System Production Demand Base, Intermediate, Peak
9	Expense Adjustments	(1,405,740)	L. 44, Production Demand
10	Subtotal Production Expenses	$ 224,084,718	Sum of Ls.1 - 9
11	Adjusted Rate Base	$ 1,170,051,684	L. 49, Production Rate Base

	Conroy M-3, Page 1	Total Transmission Cost	
12	Operation and Maintenance Expenses	$ 21,937,346	C3, page 7, Total System Transmission Demand Base, Intermediate, Peak
13	Depreciation Expenses	6,282,596	C3, page 11, Total System Transmission Demand Base, Intermediate, Peak
14	Accretion Expenses	4,325	C3, page 15, Total System Transmission Demand Base, Intermediate, Peak
15	Property Taxes	1,561,012	C3, page 17, Total System Transmission Demand Base, Intermediate, Peak
16	Other Expenses	(49)	C3, page 21, Total System Transmission Demand Base, Intermediate, Peak
17	Regulatory Credits	(7,280)	C3, page 13, Total System Transmission Demand Base, Intermediate, Peak
18	Amortization Expense	375,386	L. 23, Transmission Demand
19	Amortization of ITC	(189,529)	C3, page 19, Total System Transmission Demand Base, Intermediate, Peak
20	Expense Adjustments	(2,610,821)	L. 34, Transmisison Expense Adjustments
21	Subtotal Transmission Expenses	$ 27,352,984	Sum of Ls.12 - 20
22	Adjusted Rate Base	$ 120,023,671	L. 49, Transmission Rate Base

		Total Amortization, Exh. C3, page 25	Production	Transmission	
23	Allocation of Amortization Expense to Production and Transmission	$ 5,925,055	$ 3,659,449	$ 375,386	L. 45 Production or Transmission divided by Total times total expense adjustment L.23

		Total System	Production	Transmission	
		Expense Adjustments from Unit Cost schedules			
	Expense Adjustments assigned to Production Demand:	Exh. C3, page 31			
24	Remove ECR Expenses	$ (801,360)	$ (801,360)	$ -	
	Expense Adjustments assigned to Transmission Demand				
25	Adjustment for transfer of ITO functions	(1,504,636)	-	(1,504,636)	
26	MISO exit fee regulatory asset amortization	(1,044,188)	-	(1,044,188)	
27	Year end adjustment	803,321	496,149	50,895	L. 45 Production or Transmission divided by Total times total expense adjustment L.27
28	Annualized depreciation expenses under current rates	696,536	430,197	44,129	L. 45 Production or Transmission divided by Total times total expense adjustment L.28
29	Labor adjustment	3,272,923	2,021,432	207,358	L. 45 Production or Transmission divided by Total times total expense adjustment L.29
30	Pension & post retirement expense adjustment	(3,600,003)	(2,223,444)	(228,080)	L. 45 Production or Transmission divided by Total times total expense adjustment L.30
31	Property insurance expense adjustment	245,960	151,911	15,583	L. 45 Production or Transmission divided by Total times total expense adjustment L.31
32	Eliminate advertising expenses	(539,988)	(333,509)	(34,211)	L. 45 Production or Transmission divided by Total times total expense adjustment L.32
33	Remove out of period items	944,620	583,419	59,847	L. 45 Production or Transmission divided by Total times total expense adjustment L.33
34	Amortization of rate case expenses	(47,037)	(29,051)	(2,980)	L. 45 Production or Transmission divided by Total times total expense adjustment L.34
35	Adjustment for Swap termination regulatory asset	102,858	63,527	6,517	L. 45 Production or Transmission divided by Total times total expense adjustment L.35
36	2011 Wind Storm regulatory asset amortization	1,610,425	994,635	102,029	L. 45 Production or Transmission divided by Total times total expense adjustment L.36
37	Adjustment for injuries and damages FERC account 925	(379,162)	(234,179)	(24,022)	L. 45 Production or Transmission divided by Total times total expense adjustment L.37
38	General Management Audit regulatory asset amortization	30,528	18,855	1,934	L. 45 Production or Transmission divided by Total times total expense adjustment L.38
39	Federal & State Income Tax Adjustment	(3,780,611)	(2,334,992)	(239,523)	L. 45 Production or Transmission divided by Total times total expense adjustment L.39
40	Federal & State Income Tax Interest Adjustment	28,247	17,446	1,790	L. 45 Production or Transmission divided by Total times total expense adjustment L.40
41	Prior income tax true-ups & adjustments	(608,114)	(375,585)	(38,527)	L. 45 Production or Transmission divided by Total times total expense adjustment L.41
42	Adjustment for tax basis depreciation reduction	(85,392)	(52,740)	(5,410)	L. 45 Production or Transmission divided by Total times total expense adjustment L.42
43	Adjustment ofr amortization of investment tax credit	326,330	201,549	20,675	L. 45 Production or Transmission divided by Total times total expense adjustment L.43
44	Total Expense Adjustments	$ (4,328,743)	$ (1,405,740)	$ (2,610,821)	Sum of Ls. 24 - 43
45	Rate Base	$ 1,920,997,668	$ 1,186,451,987	$ 121,706,011	C-2, page 7, Net Rate Base, sum of production & transmisison base, intermediate, peak
	Rate Base Adjustments:				
46	ECR Plan Eliminations	(20,091,143)	(12,408,748)	(1,272,887)	L. 45 Production or Transmission divided by Total times total expense adjustment L.46
47	Adjustmentto Reflect Depreciation Reserve	(696,536)	(430,197)	(44,129)	L. 45 Production or Transmission divided by Total times total expense adjustment L.47
48	Cash Working Capital	(5,766,234)	(3,561,358)	(365,323)	L. 45 Production or Transmission divided by Total times total expense adjustment L.48
49	Net Adjusted Rate Base	$ 1,894,443,755	$ 1,170,051,684	$ 120,023,671	

LG&E Exhibit M3,page 2 of 4, Tied to Cost of Service C3 — Primary Distribution Unit Demand Costs

Purple highlighted cells are on Conroy Exhibit M2
Blue highlighted cells are inputs from Conroy Exhibit C3
all other cells are calculated

		A	B	C	
		Col. (A) = Col. (B) + Col. (C)			
	Conroy M-3, Page 2	Distribution Primary Substation Col. A amounts per M3, pg 2	Rate PS	Rate TODP	
1	Operation and Maintenance Expenses	$ 918,722	$ 88,662	$ 830,060	C3, page 7: Distribution Substation, PS-P and TOD-P
2	Depreciation Expenses	417,680	40,309	377,371	C3, page 11: Distribution Substation, PS-P and TOD-P
3	Accretion Expenses	498	48	450	C3, page 15: Distribution Substation, PS-P and TOD-P
4	Property Taxes	94,070	9,078	84,992	C3, page 17: Distribution Substation, PS-P and TOD-P
5	Other Expenses	(3)	-	(3)	C3, page 21: Distribution Substation, PS-P and TOD-P
6	Regulatory Credits	(623)	(60)	(563)	C3, page 13: Distribution Substation, PS-P and TOD-P
7	Amortization Expense	29,295	2,841	26,454	L.67
8	Amortization of ITC	(11,421)	(1,102)	(10,319)	C3, page 19: Distribution Substation, PS-P and TOD-P
9	Expense Adjustments	(119,165)	(35,717)	(83,449)	L.1 ÷ (L.1 + L.12) x L.46
10	Sub-Total Substation Expenses	$ 1,329,052	$ 104,059	$ 1,224,993	Sum of Ls.1 - 9
11	Adjusted Rate Base	$ 8,804,473	$ 849,494	$ 7,954,979	L.62
	Conroy M-3, Page 2	Distribution Primary Lines Col. A amounts per M3, pg 2	Rate PS	Rate TODP	
12	Operation and Maintenance Expenses	$ 1,932,177	$ 186,467	$ 1,745,710	C3, page 7: Distribution Primary Demand Lines, PS-P and TOD-P
13	Depreciation Expenses	643,142	62,067	581,075	C3, page 11: Distribution Primary Demand Lines, PS-P and TOD-P
14	Accretion Expenses	767	74	693	C3, page 15: Distribution Primary Demand Lines, PS-P and TOD-P
15	Property Taxes	144,849	13,979	130,870	C3, page 17: Distribution Primary Demand Lines, PS-P and TOD-P
16	Other Expenses	(4)	-	(4)	C3, page 21: Distribution Primary Demand Lines, PS-P and TOD-P
17	Regulatory Credits	(961)	(93)	(868)	C3, page 13: Distribution Primary Demand Lines, PS-P and TOD-P
18	Amortization Expense	45,189	4,382	40,807	L.68
19	Amortization of ITC	(17,586)	(1,697)	(15,889)	C3, page 19: Distribution Primary Demand Lines, PS-P and TOD-P
20	Expense Adjustments	(250,619)	(75,116)	(175,502)	L.1 ÷ (L.1 + L.12) x L.46
21	Sub-Total Lines Expenses	$ 2,496,954	$ 190,062	$ 2,306,892	Sum of Ls.12 - 20
22	Adjusted Rate Base	$ 13,581,221	$ 1,310,375	$ 12,270,846	L.63

LG&E Exhibit M3,page 2 of 4, Tied to Cost of Service C3 — Primary Distribution Unit Demand Costs

Purple highlighted cells are on Conroy Exhibit M2
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all other cells are calculated

		A	B	C	
		Col. (A) = Col. (B) + Col. (C)			
			Expense Adjustments from Unit Cost schedules		
		Total Primary	Rate PS	Rate TODP	
23	Expense Adjustments assigned to Distribution				
24	Eliminate DSM Expenses (allocate to demand & customer)	$ (286,532)	$ (98,989)	$ (187,543)	C3, page 29 PS-P and TOD-P
25	Normalized storm damage expenses (allocate to demand & customer)	(84,393)	(8,239)	(76,154)	C3, page 29 PS-P and TOD-P
26	Year end adjustment	$ 294	$ 140	$ 155	C3, page 29 PS-P and TOD-P
27	Annualized depreciation expenses under current rates	86,651	9,928	76,723	C3, page 29 PS-P and TOD-P
28	Labor adjustment	406,224	46,918	359,306	C3, page 29 PS-P and TOD-P
29	Pension & post retirement expense adjustment	(446,820)	(51,607)	(395,214)	C3, page 29 PS-P and TOD-P
30	Property insurance expense adjustment	28,523	3,257	25,265	C3, page 29 PS-P and TOD-P
31	Eliminate advertising expenses	(77,103)	(10,343)	(66,760)	C3, page 29 PS-P and TOD-P
32	Remove out of period items	110,706	12,625	98,082	C3, page 29 PS-P and TOD-P
33	Amortization of rate case expenses	(7,348)	(820)	(6,527)	C3, page 29 PS-P and TOD-P
34	Adjustment for Swap termination regulatory asset	11,928	1,362	10,566	C3, page 29 PS-P and TOD-P
35	2011 Wind Storm regulatory asset amortization	188,737	21,523	167,214	C3, page 29 PS-P and TOD-P
36	Adjustment for injuries and damages FERC account 925	(43,970)	(5,021)	(38,948)	C3, page 29 PS-P and TOD-P
37	General Management Audit regulatory asset amortization	3,540	404	3,136	C3, page 29 PS-P and TOD-P
38	Federal & State Income Tax Adjustment	(376,257)	(180,611)	(195,646)	C3, page 29 PS-P and TOD-P
39	Federal & State Income Tax Interest Adjustment	3,389	953	2,436	C3, page 29 PS-P and TOD-P
40	Prior income tax true-ups & adjustments	(72,963)	(20,521)	(52,442)	C3, page 29 PS-P and TOD-P
41	Adjustment for tax basis depreciation reduction	(9,902)	(1,131)	(8,772)	C3, page 29 PS-P and TOD-P
42	Adjustment ofr amortization of investment tax credit	37,843	4,322	33,521	C3, page 29 PS-P and TOD-P
43	Total of Other Expense Adjustments	$ (527,453)	$ (168,622)	$ 12,094	Sum of Ls.26 - 42
44	Total Primary portion of other expense adj	$ (13,175)	$ (14,421)	$ 1,246	L.57 ÷ L.47 x L.43
45	Total Primary portion of distribution exp adj	$ (356,609)	$ (96,412)	$ (260,197)	(L.24 + L.25) x (L.57÷ (L.57 + L.58))
46	Total Primary expense adjustments	$ (369,784)	$ (110,833)	$ (258,951)	Sum of Ls.44 - 45

LG&E Exhibit M3,page 2 of 4, Tied to Cost of Service C3 Primary Distribution Unit Demand Costs

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all other cells are calculated

		A	B	C	
		Col. (A) = Col. (B) + Col. (C)			
		Total System Rate Base, C3 page 5	Rate PS-P	Rate TODP	
47	Rate Base	$ 1,920,997,668	$ 25,673,931	$ 199,460,877	C3, pp 5, PS-P and TOD-P total rate base
48	Rate Base Adjustments:	C3, page 29 Total System			
49	ECR Plan Eliminations	(183,667,066)	(339,663)	(2,605,171)	C3, page 29 PS-P and TOD-P
50	Adjustmentto Reflect Depreciation Reserve	(712,846)	(9,928)	(76,723)	C3, page 29 PS-P and TOD-P
51	Cash Working Capital	(5,709,964)	(69,742)	(527,047)	C3, page 29 PS-P and TOD-P
52	Total Rate Base Adjustments	(190,089,876)	(419,332)	(3,208,942)	Sum of Ls.49 - 51
53	Adjusted Net Rate Base	$ 1,730,907,792	$ 25,254,598	$ 196,251,936	L.47 + L.52
54	Allocate Rate Base Adjustments between Substation Demand and Lines Demand:		Rate PS-P	Rate TODP	
55	Substation Demand Rate Base		$ 863,599	$ 8,085,052	C3, p 5, PS-P and TOD-P Distribution Substation
56	Primary Lines Demand Rate Base		1,332,133	12,471,488	C3, p 5, PS-P and TOD-P Distribution Lines
57	Total Primary Demand Rate Base		$ 2,195,732	$ 20,556,540	Sum of Ls.55 - 56
58	Primary Customer Rate Base		246,322	276,576	C3, p 5 PS-P and TOD-P, Primary Customer Lines and Meters (used to allocate PS-P and TOD-P distribution expense adj between Demand & Customer)
59	Rate Base Adjustments allocated to Distribution Demand, using total Rate Base		(35,863)	(330,715)	L.57 ÷ L.47 x L.52
60	Substation portion of rate base adjustment		(14,105)	(130,073)	L.55 ÷ L.57 x L.59
61	Lines portion of rate base adjustment		(21,758)	(200,642)	L.56 ÷ L.57 x L.59
62	Substation Adjusted Rate Base		$ 849,494	$ 7,954,979	L.55 + L.60
63	Lines Adjusted Rate Base		1,310,375	12,270,846	L.56 + L.61
64	Allocate Amortization Expense Adjustment between Substation Demand and Lines Demand:		Rate PS-P	Rate TODP	
65	Primary Amortization Expense Adjustment		$ 84,451	$ 652,640	C3, p 25, PS-P and TOD-P Amortization Expense
66	Primary Amortization Expense Allocated to Demand		$ 7,223	$ 67,261	L.57 ÷ L.47 x L.65
67	Substation Demand Amortization Expense		$ 2,841	$ 26,454	L.55 ÷ L.57 x L.65
68	Primary Lines Amortization Expense		4,382	40,807	L.56 ÷ L.57 x L.66
69	Total Primary Amortization Expense		$ 7,223	$ 67,261	Sum of Ls.67 - 68

LG&E Exhibit M3, Page 3 of 4 -- Tied to Cost of Service Secondary Distribution Unit Demand Costs

Purple highlighted cells are on Conroy Exhibit M2
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all other cells are calculated

		A	B	C	
		Col. (A) = Col. (B) + Col. (C)			
	Conroy M-3, Page 2	Distribution Secondary Substations	Rate PS-S	Rate TOD-S	
		Col. A amounts per M3, pg 3			
1	Operation and Maintenance Expenses	$ 1,285,962	$ 1,037,267	$ 248,695	C3, page 7: Distribution Substation, PS-S and TOD-S
2	Depreciation Expenses	584,640	471,575	113,065	C3, page 11: Distribution Substation, PS-S and TOD-S
3	Accretion Expenses	697	562	135	C3, page 15: Distribution Substation, PS-S and TOD-S
4	Property Taxes	131,672	106,208	25,464	C3, page 17: Distribution Substation, PS-S and TOD-S
5	Other Expenses	(4)	(3)	(1)	C3, page 21: Distribution Substation, PS-S and TOD-S
6	Regulatory Credits	(873)	(704)	(169)	C3, page 13: Distribution Substation, PS-S and TOD-S
7	Amortization Expense	40,869	32,950	7,919	L.83
8	Amortization of ITC	(15,987)	(12,895)	(3,092)	C3, page 19: Distribution Substation, PS-S and TOD-S
9	Expense Adjustments	(749,943)	(686,604)	(63,339)	L.1 ÷ [L.1 + L.12 + L.23] x L.57
10	Sub-Total Substation Expenses	$ 1,277,033	$ 948,355	$ 328,677	Sum of Ls.1 - 9
11	Adjusted Rate Base	$ 12,174,774	$ 9,819,256	$ 2,355,518	L.76

	Conroy M-3, Page 2	Distribution Secondary Lines	Rate PS-S	Rate TOD-S	
		Col. A amounts per M3, pg 3			
12	Operation and Maintenance Expenses	$ 739,183	$ 582,799	$ 156,384	C3, page 7: Distribution Lines, PS-S and TOD-S
13	Depreciation Expenses	246,044	193,990	52,054	C3, page 11: Distribution Lines, PS-S and TOD-S
14	Accretion Expenses	293	231	62	C3, page 15: Distribution Lines, PS-S and TOD-S
15	Property Taxes	55,414	43,690	11,724	C3, page 17: Distribution Lines, PS-S and TOD-S
16	Other Expenses	(2)	(1)	(0)	C3, page 21: Distribution Lines, PS-S and TOD-S
17	Regulatory Credits	(367)	(290)	(78)	C3, page 13: Distribution Lines, PS-S and TOD-S
18	Amortization Expense	17,231	13,578	3,652	L.84
19	Amortization of ITC	(6,728)	(5,305)	(1,423)	C3, page 19: Distribution Lines, PS-S and TOD-S
20	Expense Adjustments	(425,604)	(385,776)	(39,829)	L.1 ÷ [L.1 + L.12 + L.23] x L.57
21	Sub-Total Lines Expenses	$ 625,463	$ 442,917	$ 182,547	Sum of Ls.12 - 20
22	Adjusted Rate Base	$ 5,132,884	$ 4,046,498	$ 1,086,386	L.77

	Conroy M-3, Page 2	Distribution Secondary Transformers	Rate PS-S	Rate TOD-S	
		Col. A amounts per M3, pg 3			
23	Operation and Maintenance Expenses	$ 165,446	$ 130,444	$ 35,002	C3, page 7: Distribution Line Transformers, PS-S and TOD-S
24	Depreciation Expenses	348,148	274,493	73,655	C3, page 11: Distribution Line Transformers, PS-S and TOD-S
25	Accretion Expenses	415	327	88	C3, page 15: Distribution Line Transformers, PS-S and TOD-S
26	Property Taxes	78,410	61,821	16,589	C3, page 17: Distribution Line Transformers, PS-S and TOD-S
27	Other Expenses	(3)	(2)	(1)	C3, page 21: Distribution Line Transformers, PS-S and TOD-S
28	Regulatory Credits	520	410	110	C3, page 13: Distribution Line Transformers, PS-S and TOD-S
29	Amortization Expense	24,093	18,986	5,107	L.85
30	Amortization of ITC	(9,520)	(7,506)	(2,014)	C3, page 19: Distribution Line Transformers, PS-S and TOD-S
31	Expense Adjustments	(95,260)	(86,346)	(8,915)	L.1 ÷ [L.1 + L.12 + L.23] x L.57
32	Sub-Total Transformer Expenses	$ 512,249	$ 392,628	$ 119,622	Sum of Ls.23 - 31
33	Adjusted Rate Base	$ 7,177,116	$ 5,658,064	$ 1,519,052	L.78

LG&E Exhibit M3, Page 3 of 4 -- Tied to Cost of Service Secondary Distribution Unit Demand Costs

Purple highlighted cells are on Conroy Exhibit M2

			Expense Adjustments from Unit Cost schedules		
		Total Secondary	Rate PS-S	Rate TOD-S	
34	Expense Adjustments assigned to Distribution				
35	Eliminate DSM Expenses (allocate to demand & customer)	$ (1,221,250)	$ (1,007,437)	$ (213,813)	C3, page 29 PS-Secondary and TOD-Secondary
36	Normalized storm damage expenses (allocate to demand & customer)	(173,403)	(140,176)	(33,227)	C3, page 29 PS-Secondary and TOD-Secondary
37	Year end adjustment	$ 5,027	$ 4,769	$ 258	C3, page 29 PS-Secondary and TOD-Secondary
38	Annualized depreciation expenses under current rates	141,699	113,438	28,261	C3, page 29 PS-Secondary and TOD-Secondary
39	Labor adjustment	636,352	509,804	126,548	C3, page 29 PS-Secondary and TOD-Secondary
40	Pension & post retirement expense adjustment	(699,945)	(560,751)	(139,194)	C3, page 29 PS-Secondary and TOD-Secondary
41	Property insurance expense adjustment	47,099	37,730	9,369	C3, page 29 PS-Secondary and TOD-Secondary
42	Eliminate advertising expenses	(128,181)	(105,888)	(22,293)	C3, page 29 PS-Secondary and TOD-Secondary
43	Remove out of period items	181,656	145,497	36,159	C3, page 29 PS-Secondary and TOD-Secondary
44	Amortization of rate case expenses	(10,686)	(8,524)	(2,162)	C3, page 29 PS-Secondary and TOD-Secondary
45	Adjustment for Swap termination regulatory asset	19,696	15,778	3,918	C3, page 29 PS-Secondary and TOD-Secondary
46	2011 Wind Storm regulatory asset amortization	309,695	248,049	61,646	C3, page 29 PS-Secondary and TOD-Secondary
47	Adjustment for injuries and damages FERC account 925	(72,606)	(58,163)	(14,443)	C3, page 29 PS-Secondary and TOD-Secondary
48	General Management Audit regulatory asset amortization	5,846	4,683	1,163	C3, page 29 PS-Secondary and TOD-Secondary
49	Federal & State Income Tax Adjustment	(128,092)	(1,120,802)	992,710	C3, page 29 PS-Secondary and TOD-Secondary
50	Federal & State Income Tax Interest Adjustment	9,470	8,772	698	C3, page 29 PS-Secondary and TOD-Secondary
51	Prior income tax true-ups & adjustments	(203,886)	(188,850)	(15,036)	C3, page 29 PS-Secondary and TOD-Secondary
52	Adjustment for tax basis depreciation reduction	(16,352)	(13,099)	(3,253)	C3, page 29 PS-Secondary and TOD-Secondary
53	Adjustment for amortization of investment tax credit	62,489	50,059	12,430	C3, page 29 PS-Secondary and TOD-Secondary
54	Total of Other Expense Adjustments	$ (1,235,372)	$ (917,498)	$ 1,076,779	Sum of Ls.37 - 53
55	Total Secondary demand portion of other expense adj	$ 18,804	$ (110,618)	$ 129,423	L.70 ÷ L.58 x L.54
56	Total Secondary demand portion of distribution exp adj	(1,289,612)	(1,048,107)	(241,505)	(L.35 + L.36) x (L.70÷ (L.70 + L.71))
57	Total Secondary expense adjustments	$ (1,270,808)	$ (1,158,725)	$ (112,082)	Sum of Ls.55 - 56
58	Rate Base	$ 369,418,943	$ 295,884,998	$ 73,533,945	C3, pp 5 PS-S and TOD-S total rate base
59	Rate Base Adjustments:				
60	ECR Plan Eliminations	$ (4,716,897)	$ (3,770,825)	$ (946,072)	C3, page 29 PS-S and TOD-S
61	Adjustmentto Reflect Depreciation Reserve	(141,699)	(113,438)	(28,261)	C3, page 29 PS-S and TOD-S
62	Cash Working Capital	(997,581)	(800,464)	(197,117)	C3, page 29 PS-S and TOD-S
63	Total Rate Base Adjustments	(5,856,177)	(4,684,727)	(1,171,450)	Sum of Ls.60 - 62
64	Adjusted Net Rate Base	$ 363,562,766	$ 291,200,271	$ 72,362,495	L.58 + L.63

LG&E Exhibit M3, Page 3 of 4 -- Tied to Cost of Service Secondary Distribution Unit Demand Costs

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Line	Description	Rate PS-S	Rate TOD-S	Source
65	Allocate Rate Base Adjustments between Substation Demand and Lines Demand:	Rate PS-S	Rate TOD-S	
66	Substation Demand Rate Base	$ 10,103,322	$ 2,422,372	C3, pp 5, PS-S and TOD-S Distribution Substation
67	Primary Lines Demand Rate Base	15,584,744	3,736,598	C3, pp 5, PS-S and TOD-S Distribution Substation
68	Secondary Lines Demand Rate Base	4,163,561	1,117,220	C3, pp 5, PS-S and TOD-S Distribution Secondary
69	Secondary Transformers Lines Demand Rate Base	5,821,749	1,562,166	C3, pp 5, PS-S and TOD-S Distribution Line Transformers
70	Total Secondary Demand Rate Base	$ 35,673,376	$ 8,838,356	Sum of Ls.65 - 68
71	Secondary Customer Rate Base	3,386,777	202,565	C3, pp 5 PS-S and TOD-S, Primary and Secondary Lines, Transformers, Meters & Services (used to allocate PS-S and TOD-S distribution expense adj between Demand & Customer)
72	Rate Base Adjustments allocated to Distribution Demand, using total Rate Base	$ (564,814)	$ (140,802)	L.70 ÷ L.58 x L.63
73	Substation portion of rate base adjustment	(284,066)	(66,854)	L.66 ÷ (L.70 - L.67) x L.72
74	Lines portion of rate base adjustment	(117,063)	(30,834)	L.68 ÷ (L.70 - L.67) x L.72
75	Transformers portion of rate base adjustment	(163,685)	(43,114)	L.69 ÷ (L.70 - L.67) x L.72
76	Substation Adjusted Rate Base	$ 9,819,256	$ 2,355,518	L.66 + L.73
77	Lines Adjusted Rate Base	4,046,498	1,086,386	L.68 + L.74
78	Transformers Adjusted Rate Base	5,658,064	1,519,052	L.69 + L.75
79	Total Adjusted Rate Base -- Secondary Demand	$ 19,523,818	$ 4,960,956	Sum of Ls.76 - 78
80	Allocate Amortization Expense Adjustment between Substation Demand and Lines Demand:	Rate PS-S	Rate TOD-S	
81	Secondary Amortization Expense Adjustment	$ 964,959	$ 240,399	C3, p 25, PS-S and TOD-S Amortization Expense
82	Secondary Amortization Expense Allocated to Demand	$ 65,514	$ 16,679	L.70 - L.67 ÷ L.58 x L.81
83	Substation Demand Amortization Expense	$ 32,950	$ 7,919	L.75 ÷ L.79 x L.82
84	Secondary Lines Amortization Expense	13,578	3,652	L.77 ÷ L.79 x L.82
85	Secondary Transformers Amortization Expense	18,986	5,107	L.78 ÷ L.79 x L.82
86	Total Secondary Amortization Expense	$ 65,514	$ 16,679	Sum of Ls.83 - 85

LOUISVILLE GAS AND ELECTRIC COMPANY

CASE NO. 2012-00222

Response to Commission Staff's Third Request for Information
Dated August 28, 2012

Question No. 10

Responding Witness: Robert M. Conroy

Q-10. Refer to the responses to Items 1, 2, 3.a., 4.a., 5, 22.a., and 32 of Commission Staff's Second Request for Information ("Staff's Second Request"), all of which describe proposed changes which are intended to provide clarity. Explain whether the clarifying changes referenced in each of these responses represent LG&E's existing practice which it desires to make clear in its tariff, or if the changes represent changes in LG&E's current practices or provision of services.

A-10. The response to PSC 2-1, clarifies the determination of the 50 kW limit for the General Service rate's availability to customers by defining the limit as a twelve-month average. That has been the practice with some flexibility to allow for moving customers whose average kW load was obviously above the limit but would benefit from another rate. That same flexibility allowed a customer whose average load was barely above 50 kW, then barely below 50 kW to be left on the rate most advantageous to the customer.

In response to PSC 2-2, the first sentence should be corrected.

> *The text change in the AVAILABILITY OF SERVICE section of proposed P.S.C. No. 16, Original Sheet No. 15, limits the load that can be served on the PS (Power Service) rate to secondary customers whose <u>12-month-average monthly minimum secondary loads ~~do not~~ exceed 50 kW</u> and whose secondary service or primary service <u>12-month-average maximum loads do not exceed 250 kW</u>.*

The clarification is of the determination of the 50 kW minimum limit for secondary customer and the 250 kW maximum limit the Power Service rate's availability to customers by defining those limits as a twelve-month average. That has been the practice with some flexibility as noted above.

The response to PSC 2-3a, clarifies the determination of the 250 kW minimum limit and the 5,000 kW maximum limit of the Time-of-Day Secondary Service rate's availability to customers by defining those limits as a twelve-month average. That has been the practice with some flexibility as noted above.

The response to PSC 2-4a, clarifies the determination of the 250 kW minimum limit and the 50,000 kW maximum limit of the Time-of-Day Primary Service rate's availability to customers by defining those limits as a twelve-month average. That has been the practice with some flexibility as noted above.

The response to PSC 2-5, clarifies the determination of the 50,000 kW maximum limit of the Retail Transmission Service rate's availability to customers by defining those limits as a twelve-month average. That has been the practice with some flexibility as noted above.

The response to PSC 2-22a, clarifies existing practice as noted above with respect to the determination of customer eligibility under Rate FT. This method for determining eligibility has been LG&E's historic practice.

The response to PSC 2-32, clarifies existing practice as noted above.

LOUISVILLE GAS AND ELECTRIC COMPANY

CASE NO. 2012-00222

Response to Commission Staff's Third Request for Information
Dated August 28, 2012

Question No. 11

Responding Witness: Robert M. Conroy

Q-11. Refer to LG&E's response to Item 4.b., pages 1 and 2. Explain why the percentage increases on the annualized winter bills (11.45 percent and 15.24 percent) are so much greater than the annualized summer bills (1.42 percent and 4.64 percent) for 100 percent and 90 percent average power factors, respectively.

A-11. The current ITOD-P rate structure uses seasonal demand rates to reflect LG&E's higher cost of service during the summer months. As the attachment to the response to PSC 2-4b demonstrates, LG&E's proposed total demand rate (sum of peak, intermediate, and base charges) of $13.26/kVA is lower than the current summer total demand (sum of peak and basic charges) of $14.29/kW. Conversely, the total proposed demand rate of $13.26/kVA is greater than the current winter total demand charges of $11.49/kW. The rate differential results in a larger percentage increase when proposed rates are compared to current winter rates than when proposed rates are compared to current summer rates.

LOUISVILLE GAS AND ELECTRIC COMPANY

CASE NO. 2012-00222

Response to Commission Staff's Third Request for Information
Dated August 28, 2012

Question No. 12

Responding Witness: Robert M. Conroy

Q-12. Refer to the response to Item 6 of Staff's Second Request, page 2 of 5, the LS Underground Service section. The response states that "[t]he language referring to Custom Ordered Styles was deleted. Customers choosing to install their own lighting will be billed base (sic) on LG&E's LE tariff."

a. State whether any current customers will be moved to the Lighting Energy ("LE") tariff as a result of the proposed changes.

b. LG&E's LE tariff states that it is available to "municipalities, county governments, divisions or agencies of the state or Federal governments, civic associations, and other public or quasi-public agencies for service to public street and highway lighting systems . . . ." Explain whether LG&E intends for individuals who choose to install their own lighting to be eligible to take service under the LE tariff.

A-12. a. No current customers will be moved to Rate LE as a result of the proposed tariff change unless those customers assume ownership of lighting facilities currently owned by LG&E.

b. LG&E does not intend to alter the AVAILABILITY OF SERVICE term applicable to Rate LE so that individuals owning their own lighting facilities may be served under Rate LE. Such customers may receive power for their lighting through their standard service meter.

LOUISVILLE GAS AND ELECTRIC COMPANY

CASE NO. 2012-00222

Response to Commission Staff's Third Request for Information
Dated August 28, 2012

Question No. 13

Responding Witness: Robert M. Conroy

Q-13. Refer to LG&E's response to Item 6 of Staff's Second Request, pages 3 and 5 of 5, the LS and RLS Term and Conditions sections. Explain why it is necessary to add language prohibiting the temporary suspension of lighting service.

A-13. LG&E's practice, if temporary turnoffs were allowed, would be to remove the facilities; pole and fixture as appropriate. LG&E believes the temporary suspension of lighting would be administratively burdensome. In addition, if temporary turnoffs were allowed, the Company would have assets in services with no revenue to cover their costs. Lights would be reported by the public as failing when they were requested to be turned-off by a customer. Historically this has not been a problem. However, given the economic issues faced by some customers, LG&E has received requests from municipals for such an action in order to reduce their monthly expenses.

LOUISVILLE GAS AND ELECTRIC COMPANY

CASE NO. 2012-00222

Response to Commission Staff's Third Request for Information
Dated August 28, 2012

Question No. 14

Responding Witness: J. Clay Murphy

Q-14. Refer to LG&E's response to Item 22.d. of Staff's Second Request.

a. Explain how many days do over/under-deliveries over-lap, and if the impact of imbalances on LG&E's system reliability is mitigated by volumes netting against each other.

b. Explain whether LG&E has discussed this decrease in the imbalance tolerance with Rate FT customers, and if so describe the customer feedback received by LG&E.

A-14. a. Netting among customer over- and under-deliveries occurs every day. The netting of daily over- and under-deliveries on a given day mitigates the negative impact of such daily imbalances on system reliability for that day. The netting of daily imbalances on one day against daily imbalances that occur on the following day does not mitigate the negative impact of imbalances on system reliability.

The data presented in response to PSC 2- 22(d) are the result of daily netted over- and under-deliveries for each of the 366 days during the test year. (The test year contained Leap Year Day, February 29, 2012.) On 205 of the 366 days, customers net over-delivered to LG&E; on 161 of the 366 days, customers net under-delivered to LG&E. Thus, the results presented are the results of netted over- or under-deliveries for each of the 366 days. For example, daily nominations were outside (either over or under) the 10% daily imbalance tolerance on 118 days, or about 32% of the time. Daily nominations were outside of the 5% imbalance tolerance (either over or under) on 214 days, or about 58% of the time.

LG&E is proposing to change the daily balancing tolerances in order to incent customers served under Rate FT (or pool managers served under Rider PS-FT) to improve the customer's nomination accuracy and facilitate balancing of the gas system. It is for this reason that LG&E has requested the change in the daily tolerance for both Rate FT (from 10% to 5%) and Rider PS-FT (from 5% to 2%). As discussed in LG&E's response to Question No. 15, LG&E expects that, as a result of changing the daily imbalance tolerance, customers will change their behavior and improve the accuracy of their daily nominations in order to avoid or mitigate their exposure to the Utilization Charge for Daily Imbalances.

b. LG&E did not have discussions about this proposed tariff change with customers prior to filing this proposed change with the Commission. However, LG&E did provide notice of its rate case filing in local newspapers as well as in bill inserts. In addition, LG&E is aware of its customers' balancing needs and preferences. As discussed in LG&E's response to PSC 2-22(d), this specific change has been proposed to improve system reliability for all customers. LG&E plans to provide customers with notice of the change as soon as practicable assuming approval is received from the Commission. LG&E believes that the change in the daily balancing tolerance will encourage greater accuracy in providing daily gas supply nominations to LG&E. As a result of improved accuracy, the customer will be able to mitigate the impact of the proposed change in the daily tolerance threshold.

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Question No. 15

Responding Witness: J. Clay Murphy

Q-15. Refer to LG&E's response to Item 22.e. of Staff's Second Request, with reference to the $6,971 in Utilization Charges identified. Provide the highest individual test year Rate FT customer imbalance and the corresponding incremental UCDI charge that would be attributable to the change from ten to five percent imbalance tolerance.

A-15. Of the Rate FT customers not served in pools that will be subject to the change in the daily imbalances tolerance from ten to five percent, the customer with the largest share of the increase in Utilization Charge for Daily Imbalances ("UCDI") charges is responsible for an estimated $3,952 of the estimated total $6,971 in incremental annual UCDI charges. Had the lower tolerance been in place for the 12 months ended March 31, 2012, LG&E estimates that the volumes subject to the UCDI would have increased from 139,359 Mcf to 150,256 Mcf for this customer.

LG&E also believes that the change in the daily balancing tolerance would have caused this customer (and other customers) to better manage gas deliveries to LG&E with the result that actual daily imbalances would have been lower. This is the desired effect of the proposed change. In other words, improved accuracy in the provision of nominations by the customer will enable the customer to mitigate or avoid the Utilization Charge for Daily Imbalances.

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Dated August 28, 2012

Question No. 16

Responding Witness: J. Clay Murphy

Q-16. Refer to the response to Item 22.i. of Staff's Second Request.

a. If the proposed tariff revision regarding the "Minimum Daily Threshold Requirement and Charge" is approved, explain whether LG&E intends to switch approximately eight customers from Rate FT to a firm sales service.

b. If the answer to a. above is yes, provide details concerning the daily and annual usage of the individual customers sufficient to show their ineligibility for Rate FT.

c. If the answer to a. above is no, confirm that LG&E intends to grandfather these customers if the tariff revision is approved.

d. Explain whether LG&E has communicated this proposed tariff addition to the eight customers who may be subject to being switched to firm sales service as referenced in this response.

e. Provide the highest individual test year Rate FT customer variance from required usage and the corresponding Minimum Daily Threshold Charge attributable to this customer if this charge had been available during the test year.

A-16. a. LG&E plans to work with these eight customers to remove them from Rate FT and transfer them to a rate for which they qualify that meets the character of service they require, *viz.*, either Rate CGS or Rate IGS. The proposed "Minimum Daily Threshold Requirement and Charge" was added to Rate FT in order to provide customers that no longer meet the minimum daily threshold under Rate FT with an incentive to request a transfer to a rate under which they are qualified to receive service, and in the absence of such a request to provide LG&E with a tariffed mechanism to transfer the customer.

b. Service under Rate FT requires that the customer use at least 50 Mcf/day. Each of the eight customers used less than 50 Mcf/day for more than 120 days during the 12 months ended March 31, 2012.

Customer	Days With Use Less Than 50 Mcf	Days in 12 Months Ended March 31, 2012	Percentage
A	245	366	67%
B	129	366	35%
C	254	366	69%
D	133	366	36%
E	221	366	60%
F	219	366	60%
G	315	366	86%
H	242	366	66%

Therefore, in each case, the customer used less than 50 Mcf/day for at least one third of the year, well below the minimum requirement stipulated in the tariff.

c. LG&E has no plans to grandfather customers that currently do not qualify for Rate FT. Additionally, LG&E has no plans to grandfather customers that may currently qualify for Rate FT, but may fail to qualify in the future. Please see response to Question No. 16 (d) below.

d. LG&E did not discuss this proposed tariff change with customers prior to filing this proposed change with the Commission. However, LG&E did provide notice of its rate case filing in local newspapers as well as in bill inserts. As discussed in LG&E's response to PSC 2-22(i), given that customers that do not meet the criteria (large volume, high load factor, non-space-heating customers using at least 50 Mcf/day) cannot elect service under Rate FT, customers who consistently do not meet the same criteria do not belong on Rate FT. However, LG&E has had communications with customers whose gas consumption falls below the minimum daily use for extended periods of time. LG&E has attempted to work with customers to determine reasons for non-qualification and to remove them from Rate FT and transfer them to a more appropriate rate for which they qualify. Because of the lower distribution charge associated with Rate FT, these customers have no incentive to voluntarily transfer to a more appropriate rate. In response to LG&E's inquiries, customers often forecast load increases and a return to qualifying status, but forecasted load increases generally do not materialize.

LG&E plans to provide customers with notice of the change as soon as practicable assuming approval is received from the Commission. LG&E also believes that the changes proposed in connection with the "Minimum Daily

Threshold Requirement and Charge" will encourage non-qualifying customers to seek a more appropriate rate schedule under which to be served. Removing non-qualifying customers can be expected to improve the overall class load factor for Rate FT.

e. Customer G listed in the response to Question No. 16(b) above had the highest number of days with gas consumption less than 50 Mcf/day. This customer failed to use the minimum requirement on 315 days of the 366 days in the test year, or 86% of the time. Had the Minimum Daily Threshold Charge been in effect Customer G would have been charged an estimated $6,532.

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Question No. 17

Responding Witness: Lonnie E. Bellar

Q-17. Refer to the response to Item 22.j. of Staff's Second Request indicating that Rate FT customers are "generally" served from high pressure mains. Explain whether any Rate FT customers are served from non-high pressure mains, and, if so, whether the proposed Rate FT tariff should be revised to include the "Gas Line Tracker" for such customers.

A-17. Rate FT includes customers served from transmission lines, high pressure, and non-high pressure mains. While there are Rate FT customers served from lines that are not categorized as high pressure or transmission, their volumes are small when compared to the entire Rate FT class. As a result, the Rate FT customers served from the transmission lines and high pressure mains are responsible for the vast majority of the volumes associated with Rate FT, and therefore the Gas Line Tracker should not apply to this rate schedule.

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Question No. 18

Responding Witness: J. Clay Murphy

Q-18. Refer to the response to Item 22.m. of Staff's Second Request, the change from 10 A.M. to 8 A.M. for the nomination deadline. Explain whether LG&E has discussed this change with Rate FT customers and pool managers, and, if so, describe the feedback received by LG&E.

A-18. LG&E did not have discussions about this proposed tariff change with customers (or their pool managers) prior to filing this proposed change with the Commission. However, LG&E did provide notice of its rate case filing in local newspapers as well as in bill inserts. In addition, LG&E has often had discussions with suppliers, pool managers, or customers who fail to provide timely or complete nominations in an attempt to address this concern. This change is not expected to primarily impact customers in the provision of daily nominations, but rather the customer's supplier or their pool manager.

As discussed in LG&E's response to PSC 2-22(m), this change is intended to assist LG&E in its daily purchasing and system planning process by requiring customers to provide LG&E with a timely and accurate nomination in an earlier time frame.

LG&E plans to provide customers with notice of the change as soon as practicable assuming approval is received from the Commission. LG&E believes that the change in the nomination deadline will provide LG&E with the ability to take into account deliveries by end-use transportation customers under Rate FT or Rider PS-TS. Having end-use transportation data before purchasing and dispatch decisions are made for the following day will enable LG&E to avoid suboptimal purchasing decisions.

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Question No. 19

Responding Witness: J. Clay Murphy

Q-19. Refer to the response to Item 26.e. of Staff's Second Request. Confirm that only three of the inquiries listed involve customers with estimated annual usage that would qualify them for the proposed Gas Transportation Service/Firm Balancing Service ("TS-2") Rider and the 25,000 Mcf threshold.

A-19. LG&E agrees that of the transportation service inquiries listed in the table included in response to Commission's Second Data Request Question No. 26(e), only three of the customers that inquired would have been eligible for transportation service under proposed Rider TS-2.

However, such inquiries are not the means on which to base a proposed transportation service threshold. More importantly, these inquiries support LG&E's experience that customer desire for transportation services is relatively low.

The Commission in its Order in Case No 2010-00146 dated December 28, 2010, stated that the "Commission does not advocate mandating or legislating volumetric thresholds for gas transportation service" and went on to indicate that "the LDCs are best equipped to propose and implement their own systems' products and programs". (Order at p. 16) As stated in LG&E's response to Commission's Second Data Request Question No. 85, LG&E considered several factors and principles in determining its proposal to expand transportation service.

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Question No. 20

Responding Witness: J. Clay Murphy

Q-20. Refer to the response to Item 26.m. of Staff's Second Request. Explain whether LG&E has considered making telemetry an option rather than a requirement for potential TS-2 customers, and provide a description of all other methods of metering or meter reading besides the use of telemetry equipment by which customers could manage imbalances.

A-20. LG&E did consider making telemetry optional under Rider TS-2. However, given the value of daily gas consumption information for the customer (and its supplier) in managing imbalances and for LG&E in managing its gas system, LG&E is proposing to require telemetry for service under Rider TS-2.

Absent the proposed telemetry, in order for both LG&E and the customer to access daily metered volumes, the customer could take a daily physical meter reading at its facility at the close of each gas day at 10:00 AM, tabulate and convert the reading to a daily metered volume, and transmit that information to LG&E each day.

LG&E did consider requiring an upfront payment for the telemetry as required under Rate FT, which would eliminate the on-going payment by customers for such telemetry service.

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Question No. 21

Responding Witness: J. Clay Murphy

Q-21. Refer to the response to Items 26.m. and 27.a. of Staff's Second Request. Confirm that an existing Gas Transportation Service/Standby ("TS") customer electing to become a TS-2 customer and acting as its own pool manager would experience an increase in fixed monthly charges, if approved as proposed, from the current $153 administrative charge to $975 ($600 TS-2 administrative charge + $300 monthly telemetry charge + $75 PS-TS-2 Administrative Charge).

A-21. Prior to November 1, 2013, a customer served under Rider TS would experience an increase in fixed monthly charges from $153 to $592 to reflect the full allocation of costs to the administrative charge for Rider TS. Beginning with its November 2013 invoice, a customer transferring from Rider TS to Rider TS-2 would experience an increase in fixed monthly charges from $592 to $975 to reflect the full allocation of the cost of metering and acting as its own pool manager. These new charges reflect the costs that LG&E is currently incurring in order to provide the incremental administrative activities and metering associated with the transportation service.

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Question No. 22

Responding Witness: J. Clay Murphy

Q-22. Considering the proposed increase in the monthly charge for TS/TS-2 customers, provide a calculation of the gas cost savings per Mcf that would be required in order for a customer using 25,000 Mcf per year to find transportation service pursuant to this rider to be cost effective.

A-22. In order for a customer using 25,000 Mcf per year to save money under LG&E's proposed Rider TS-2, the customer must have gas delivered to its facility that is at least $0.468/Mcf less than the cost of gas it would otherwise purchase from LG&E. That amount can be calculated as follows: [{($600 + $300 + $75) x 12} / 25,000 Mcf].

LG&E does not believe that this criterion is a valid one for judging the cost to charge the customer in order to administer the transportation program. Savings cannot be guaranteed under transportation programs. It is, however, important that tariffs be formulated to ensure that the costs to administer the transportation programs are borne by transportation customers and not subsidized by others.

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Question No. 23

Responding Witness: J. Clay Murphy

Q-23. Refer to the response to Item 27.c. of Staff's Second Request, the reference to the required pool membership in Duke Energy Kentucky, Inc.'s ("Duke Kentucky") Rate Schedule Full Requirements Aggregation Service ("FRAS") applicable to Rate FT-L.

a. Explain whether LG&E is aware that the eligibility threshold for Duke Kentucky's Rate FT-L is 20,000 Ccf, or 2,000 Mcf per year.

b. Explain whether the characteristics of customers using 2,000 Mcf per year make pool membership relatively more important for purposes of imbalance management and system reliability than for customers using 25,000 Mcf per year.

c. Explain whether LG&E is aware that, in Columbia Gas of Kentucky, Inc.'s ("Columbia") Delivery Service Rate Schedule ("DS") referenced in response to Item 85 of Staff's Second Request, there is no requirement for pool management or aggregation services.

d. Explain whether LG&E is aware that there is no administrative charge for aggregation service Suppliers or Rate FT-L customers with respect to FRAS pursuant to Duke's FRAS tariff.

A-23. a. LG&E is aware that the eligibility threshold for Duke Kentucky's Rate FT-L is 20,000 Ccf, or 2,000 Mcf per year.

b. Lowering transportation service thresholds to include an increasing number of customers which are primarily space heating in character will make it more challenging for LG&E to balance its gas system and maintain system reliability. LG&E believes this concern is valid at the 25,000 Mcf per year level and is further supported at volumes below the 25,000 Mcf per year threshold level.

Rider TS-2 customers should be required to join pools in order to mitigate customer imbalance concerns, preserve system reliability, and minimize administrative costs associated with this transportation service. Additionally, this requirement recognizes an apparent preference by Rate FT customers to join pools as explained in LG&E's response to PSC 2-28(b).

However, pool membership is not the most important factor in maintaining system reliability. The balancing provisions included in Rider PS-TS-2 are imperative to maintaining system reliability. The balancing provisions set forth in Rider PS-TS are not otherwise provided for in Rider TS-2. Those balancing provisions are described under the sections titled "Action Alerts", "Imbalances", "Cash-Out Provision For Monthly Imbalances", "Variations in MMBtu Content", and "Nominations and Nominated Volume". If a Rider TS-2 customer were not required to join a pool, then it would be necessary for the above balancing provisions incorporated in Rider PS-TS-2 to be transferred to Rider TS-2. This approach would be similar to the design of Rate FT and Rider PS-FT.

c. LG&E is aware that Columbia Gas of Kentucky, Inc.'s Delivery Service Rate Schedule ("Rate DS") does not contain a requirement for pool management or aggregation services. As stated in response to Question No. 23(b) above, if a Rider TS-2 customer is not required to join a Rider PS-TS-2 pool, then it would be necessary to incorporate into Rider TS-2 the balancing provisions found in Rider PS-TS-2. Similarly, Columbia Gas of Kentucky, Inc.'s Rate DS incorporates the balancing provisions applicable to customers served under Rate DS.

d. LG&E is aware that there is no administrative charge for aggregation service applicable to either Suppliers or Rate FT-L customers with respect to Duke Kentucky's Rate FRAS. Duke Kentucky's "Full Requirements Aggregation Service" ("Rate FRAS") is a service that allows suppliers to deliver gas to Duke Kentucky for two or more customers enrolled in a pool. Some of the activities undertaken by Duke Kentucky to implement Rate FRAS include entering into an "Aggregation Agreement" with each supplier, processing nominations for gas to be delivered, ensuring that suppliers comply with the "Supplier Code of Conduct," providing customer information to the supplier, and billing of the supplier. Additionally, customers or their suppliers are required to take service under Rate IMBS and Duke Kentucky must ensure that suppliers comply with those balancing provisions under Rate IMBS. In LG&E's experience, there are administrative costs associated with each of these activities. LG&E cannot confirm the rate allocation methodology used by Duke Kentucky to recover such costs. If these costs are not being recovered from aggregation service suppliers pursuant to Rate FRAS, then they may be recovered through cost components in one or more other rates.

LG&E has proposed to more closely follow cost causation principles by allocating costs associated with providing pooling service to pool managers under Rider PS-TS-2 and Rider PS-FT. Recovery of those costs through a monthly Administrative Charge is appropriate because these administrative costs generally do not vary with the amount of gas consumed. See LG&E's response to PSC 2-22(f). If there were no administrative charge included in either Rider PS-TS or PS-FT, then it would be necessary to recover those costs by increasing the Administrative Charge in either Rider TS or Rate FT, as applicable. Without the administrative efficiencies created by pools, these administrative costs could increase.

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Question No. 24

Responding Witness: Lonnie E. Bellar

Q-24. Refer to the response to Item 29 of Staff's Second Request. Explain whether LG&E plans to make semi-annual filings with GLT rates to be effective January 1 and recalculated rates with a true-up factor effective June 1 each year.

A-24. Yes, LG&E expects to make semi-annual filings for the GLT. The first filing would be around November 1 with rates to be effective January 1. The second filing would recalculate the rate to include a true-up factor effective June 1, similar to the DSM mechanism.

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**Response to Commission Staff's Third Request for Information
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Question No. 25

Responding Witness: J. Clay Murphy

Q-25. Refer to the response to Items 30.b. and c. of Staff's Second Request.

a. Explain how the ability to implement interim reductions as well as increases with 20 days' notice, with the decision being within the control of LG&E, would necessarily result in a *de facto* monthly GSC rate.

b. Potential increases in under-collections without offsetting over-collections could be controlled by LG&E through a tariff change allowing but not requiring interim increases as well as reductions. Explain why imposing carrying charges on under-collections is preferable in managing the effect of the downward volatility in gas cost recovery that LG&E anticipates resulting from its proposal.

A-25. a-b. As proposed in the data request, the ability to implement interim reductions as well as increases upon 20 days' notice could result in a monthly Gas Supply Clause ("GSC"). LG&E would have the right to request monthly changes (either increases or decreases), and the Commission could approve or deny LG&E's request.

However, LG&E is not proposing to make interim increases upon 20 days' notice. The referenced language in LG&E's GSC that states "[t]he Company may make out-of-time filings when warranted" requires a notice of 30 days. Pursuant to this language, proposed increases in rates could be expected to occur only under the most extraordinary circumstances. However, reductions pursuant to the 20 day notice provision would be more routine. LG&E is only proposing to make decreases upon 20 days' notice.

Except for the period from April 2001 through July 2001 when LG&E was required by Commission Order in Administrative Case No. 384 dated March 2, 2001, LG&E has only once made an out-of-time filing. LG&E filed for a reduction applicable to December 2005 and January 2006 in Case No. 2005-00454. That filing reflected falling prices following the earlier price run up associated with Hurricanes Katrina and Rita. LG&E has never requested an out-of-time increase in its quarterly GSC recovery mechanism.

Furthermore, while LG&E may file for such changes, any such increase (or decrease) must be approved by the Commission in order to become effective. LG&E wants to make reduced gas costs available to customers and yet continue to protect them from upward price volatility through the operation of the quarterly GSC.

Therefore, historic practice combined with other aspects of the proposal would not indicate that it is LG&E's intention or objective to implement a *de facto* monthly GSC.

Protecting customers from upward price volatility was a guideline offered by the Commission in its Order in Administrative Case No. 384 dated July 17, 2001. One of the ways in which LG&E is able to accomplish that goal is through its quarterly GSC mechanism. LG&E considers that protecting its customers from upward price volatility is important, as is passing along lower gas costs on a timely basis. Therefore, LG&E does not anticipate using the mechanism to adjust gas rates upward on a monthly basis except under the most extraordinary of circumstances. Consequently, LG&E believes it is preferable to reflect carrying charges in the calculation of over- or under-collections rather than resort to a monthly GSC in order to manage over- and under-collections.

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Question No. 26

Responding Witness: J. Clay Murphy

Q-26. Refer to the response to Item 31.a. of Staff's Second Request. Explain whether LG&E has considered adding a clarifying statement to its proposed language addition that such a customer could be served pursuant to a special contract.

A-26. As currently proposed the referenced tariff language states in part that "Company shall not be obligated to provide natural gas or natural gas service under any standard natural gas rate schedule on a standby, back-up, supplemental or other basis…." to the indicated customers. It was not LG&E's intention to preclude service under a special contract mutually agreeable to both parties and approved by the Commission. Therefore, LG&E is agreeable to amplifying the proposed language by adding the following sentence: "Company and Customer may mutually agree to enter into a special contract for standby, back-up, supplemental or other service subject to the approval of the Kentucky Public Service Commission."

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Question No. 27

Responding Witness: Paul Gregory "Greg" Thomas

Q-27. Refer to the response to Item 31.b. of Staff's Second Request. Confirm that LG&E will assume ownership of gas service lines in the event of repairs in addition to events of replacement and installation of new gas service lines.

A-27. Whenever a repair is needed to a customer's service line, LG&E or its contractors will perform the repair and LG&E will assume going-forward responsibility for the service line. LG&E will not, however, assume ownership of the service line. If the repair requires the Company to make a capital investment, such as the replacement of a gas meter loop, LG&E will only assume ownership of the specific asset that is installed. Whenever a new service line is installed or an existing service line is replaced, LG&E or its contractors will perform the installation or replacement and LG&E will assume going-forward responsibility and ownership of the service line.

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Question No. 28

Responding Witness: Paul W. Thompson

Q-28. Refer to page 9, lines 15-21 of the Testimony of Paul W. Thompson, and the responses to Items 37 and 38 of Staff's Second Request.

a. Given the experience during the first year of operation of Trimble County Unit 2 ("TC2"), explain why LG&E and its sister company, Kentucky Utilities Company ("KU"), expect the test-year level of operation and maintenance costs associated with TC2 to reflect the "going-forward operation and maintenance expenses associated with operating the generating unit . . . ."

b. The response to Item 37 identifies several matters that were addressed during a spring 2012 planned outage of TC2 while the attachment to the response to Item 38 shows the level of expenses, by account, incurred for the operation of TC2 during the test year. Explain whether any of the specific expenses are expected to decline as a result of the activities performed during the outage

A-28. a. The amount of O&M expense for TC2 during the test year was approximately $11 million on a net (of IMEA/IMPA share) basis. Costs for 2012 and 2013 are expected to be marginally higher than that, at $13 million and $12 million respectively, with the level for 2014 projected at $16 million. The costs increase over time from the test year due to inflation and additional maintenance including planned outages, as would be expected in the life cycle of any coal-fired unit.

b. The spring 2012 outage was primarily for the purpose of inspecting key components prior to the expiration of the warranty, and for addressing known issues that were impacting operations. It is not expected that the resolution of those issues will lower expenses, but rather will improve reliability. As noted in part a above, the level of expenses for TC2 is expected to increase slightly in 2012 and 2013 compared to the test year amount.

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Question No. 29

Responding Witness: Paul W. Thompson

Q-29. Refer to the response to Item 39 of Staff's Second Request. Confirm that the costs shown in the attachment for the 19 additional people hired to work at TC2 since the test year in LG&E's last rate case are included in the expenses provided in the response to Item 38 of Staff's Second Request.

A-29. Yes, the labor costs associated with the additional 19 people hired for Trimble County 2 are included in the expense amount provided in the response to LG&E PSC 2-38.

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Question No. 30

Responding Witness: Paul W. Thompson

Q-30. Refer to the response to Item 40 of Staff's Second Request. In the same format used in the attachment to the response, provide the maintenance expense incurred by LG&E in calendar year 2011 and the test year. Also, provide the actual maintenance expense incurred in the first half of 2012 and the projected expense for the remainder of 2012.

A-30. See attached.

Rate Case Analysis - Outages (Nonlabor)

US$ 000

	Actual 2011	TYE 31-Mar-2012	Actual First Half 2012	Projection Second Half 2012	Projection 2012
Mill Creek 1	567	633	38	1,450	1,488
Mill Creek 2	22	4,438	5,072	58	5,130
Mill Creek 3	5,403	2,618	138	550	688
Mill Creek 4	579	60	2,526	(13)	2,513
Total	6,571	7,749	7,774	2,045	9,819
Trimble Co 1	4,050	4,274	(123)	0	(123)
Trimble Co 2	55	69	264	(15)	249
Total	4,105	4,343	141	(14)	126
Cane Run 4	609	5,215	4,119	59	4,178
Cane Run 5	2,022	2,174	-	-	-
Cane Run 6	(22)	1,397	1,251	2	1,253
Total	2,609	8,786	5,370	61	5,431
Total Steam	13,285	20,878	13,285	2,092	15,376
Trimble Co 5	-	-	-	2	2
Trimble Co 6	-	-	-	2	2
Trimble Co 7	-	-	-	2	2
Trimble Co 8	-	-	-	2	2
Trimble Co 9	(1)	(1)	-	2	2
Trimble Co 10	-	-	-	2	2
Total	(1)	(1)	-	11	11
Paddy'S Run 13	564	23	(6)	29	23
Brown 5	91	22	-	-	-
Brown 6	3	(10)	10	-	10
Brown 7	3	(9)	22	25	47
Total	98	4	32	25	57
Total CTs	661	25	26	65	91
Dix Dam					
Grand Total	13,946	20,903	13,311	2,157	15,468

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Response to Commission Staff's Third Request for Information
Dated August 28, 2012

Question No. 31

Responding Witness: Lonnie E. Bellar

Q-31. Refer to the response to Item 63.c. of Staff's Second Request. Explain the increase in off-system sales and margins in 2011 as compared to 2009 and 2010.

A-31. While many factors can influence the year to year changes in OSS volumes and margins, the overwhelming driver of why 2011 sales margins and volumes were greater than 2010 and 2009 was due to the additional generation from Trimble County 2 when it became available for dispatch in January 2011.

LOUISVILLE GAS AND ELECTRIC COMPANY

CASE NO. 2012-00222

Response to Commission Staff's Third Request for Information
Dated August 28, 2012

Question No. 32

Responding Witness: John J. Spanos

Q-32. Refer to the responses to Items 64, 94, and 95 of Staff's Second Request, all of which relate to depreciation with 94 and 95 specifically relating to the depreciation and planned retirement of the Cane Run generating units.

a. The response to Item 94.b. indicates that each generating unit is expected to have a net negative 10 percent salvage value when retired. The response to Item 95.c. states that no estimate of salvage has been developed since there is currently no intention to take the facilities down to a natural state. Given LG&E's plan to stabilize rather than dismantle and remove these generating facilities, explain why the depreciation rates for these units should include a component for negative net salvage.

b. For each of the Cane Run utility plant items for which a proposed depreciation rate and related expense is shown in the response to Item 64, provide the depreciation rate and depreciation expense based on an expected salvage value of zero when the units are retired

A-32. a. While the Company has no current plans to take the facilities down to a natural state, there are still significant costs to stabilizing the facilities. As discussed in the response to PSC 2-95(b), LG&E currently estimates costs to stabilize the Cane Run Facility to be $8.6 million. Further, while there are currently no plans to immediately dismantle these plants, there is the possibility of dismantlement in the future (as is the case with Paddy's Run and Canal), which would lead to much higher costs than included in the response to PSC 2-95(b). As such, the 10 percent negative net salvage used in the depreciation study represents a reasonable estimate of the costs associated with retiring these facilities.

b. See attached for the depreciation rates and expense for the Cane Run plant using zero percent net salvage. Note that as discussed in the response to Question No. 38(b), the book reserve for certain Cane Run units were rebalanced to better match the retirement dates and net salvage estimates for each unit. The same book reserve amounts are used in the attached file.

Additionally, note that the depreciation rates and accruals in the attached will not recover any of the costs expected to stabilize these plants upon retirement that were discussed in the response to PSC 2-95(b). Instead, under a scenario with zero net salvage these costs would be recovered by future customers that would not benefit from the use of these facilities.

LOUISVILLE GAS AND ELECTRIC COMPANY
ELECTRIC PLANT

TABLE 1. SUMMARY OF ESTIMATED SURVIVOR CURVES, NET SALVAGE, ORIGINAL COST, BOOK DEPRECIATION RESERVE AND CALCULATED ANNUAL DEPRECIATION RATES AS OF DECEMBER 31, 2011

	ACCOUNT	SURVIVOR CURVE		NET SALVAGE PERCENT	ORIGINAL COST	BOOK DEPRECIATION RESERVE	FUTURE ACCRUALS	CALCULATED ANNUAL ACCRUAL AMOUNT	CALCULATED ANNUAL ACCRUAL RATE	COMPOSITE REMAINING LIFE
	(1)	(2)		(3)	(4)	(5)	(6)	(7)	(8)=(7)/(4)	(9)=(6)/(7)
	DEPRECIABLE PLANT									
	STEAM PRODUCTION PLANT									
311.00	STRUCTURES AND IMPROVEMENTS									
	CANE RUN UNIT 1	FULLY ACCRUED	*	0	4,233,239.48	4,656,563	(423,324)	0	-	-
	CANE RUN UNIT 2	FULLY ACCRUED	*	0	2,102,422.45	2,312,665	(210,243)	0	-	-
	CANE RUN UNIT 3	FULLY ACCRUED	*	0	3,536,934.45	3,890,628	(353,694)	0	-	-
	CANE RUN UNIT 4	100-S1	*	0	4,084,601.80	4,493,062	(408,460)	0	-	-
	CANE RUN UNIT 4 SCRUBBER	100-S1	*	0	760,360.00	836,396	(76,036)	0	-	-
	CANE RUN UNIT 5	100-S1	*	0	6,266,327.41	6,270,959	(4,632)	0	-	-
	CANE RUN UNIT 5 SCRUBBER	100-S1	*	0	1,696,435.00	1,866,079	(169,644)	0	-	-
	CANE RUN UNIT 6	100-S1	*	0	27,476,428.51	20,351,263	7,125,166	1,783,925	6.49	4.0
	CANE RUN UNIT 6 SCRUBBER	100-S1	*	0	2,004,301.46	2,204,732	(200,431)	0	-	-
	MILL CREEK UNIT 1	100-S1	*	(14)	19,891,316.24	17,615,350	5,060,751	254,260	1.28	19.9
	MILL CREEK UNIT 1 SCRUBBER	100-S1	*	(14)	1,709,710.55	1,949,070	0	0	-	-
	MILL CREEK UNIT 2	100-S1	*	(14)	11,532,774.58	9,977,701	3,169,662	146,213	1.27	21.7
	MILL CREEK UNIT 2 SCRUBBER	100-S1	*	(14)	1,393,404.00	1,588,481	0	0	-	-
	MILL CREEK UNIT 3	100-S1	*	(14)	24,500,220.48	20,580,339	7,349,912	292,422	1.19	25.1
	MILL CREEK UNIT 3 SCRUBBER	100-S1	*	(14)	362,867.00	413,668	0	0	-	-
	MILL CREEK UNIT 4	100-S1	*	(14)	64,262,882.75	38,607,501	34,652,185	1,191,499	1.85	29.1
	MILL CREEK UNIT 4 SCRUBBER	100-S1	*	(14)	5,330,551.76	4,985,213	1,091,616	37,612	0.71	29.0
	TRIMBLE COUNTY UNIT 1	100-S1	*	(15)	115,104,803.30	61,530,223	70,840,301	1,961,688	1.70	36.1
	TRIMBLE COUNTY UNIT 1 SCRUBBER	100-S1	*	(15)	493,909.75	366,848	201,148	5,516	1.12	36.5
	TRIMBLE COUNTY UNIT 2	100-S1	*	(15)	25,993,297.87	310,077	29,582,216	565,651	2.18	52.3
	TOTAL ACCOUNT 311 - STRUCTURES AND IMPROVEMENTS				322,736,788.84	204,806,818	157,226,493	6,238,786	1.93	25.2

LOUISVILLE GAS AND ELECTRIC COMPANY
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TABLE 1. SUMMARY OF ESTIMATED SURVIVOR CURVES, NET SALVAGE, ORIGINAL COST, BOOK DEPRECIATION RESERVE AND CALCULATED ANNUAL DEPRECIATION RATES AS OF DECEMBER 31, 2011

	ACCOUNT	SURVIVOR CURVE		NET SALVAGE PERCENT	ORIGINAL COST	BOOK DEPRECIATION RESERVE	FUTURE ACCRUALS	CALCULATED ANNUAL ACCRUAL AMOUNT	CALCULATED ANNUAL ACCRUAL RATE	COMPOSITE REMAINING LIFE
	(1)	(2)		(3)	(4)	(5)	(6)	(7)	(8)=(7)/(4)	(9)=(6)/(7)
312.00	BOILER PLANT EQUIPMENT									
	CANE RUN UNIT 1	FULLY ACCRUED	*	0	1,052,270.58	1,157,498	(105,227)	0	-	-
	CANE RUN UNIT 2	FULLY ACCRUED	*	0	132,275.78	145,503	(13,227)	0	-	-
	CANE RUN UNIT 3	FULLY ACCRUED	*	0	705,480.33	776,028	(70,548)	0	-	-
	CANE RUN UNIT 4	50-R1.5	*	0	31,327,230.07	22,533,292	8,793,938	2,239,202	7.15	3.9
	CANE RUN UNIT 4 SCRUBBER	50-R1.5	*	0	17,050,367.50	18,755,404	(1,705,036)	0	-	-
	CANE RUN UNIT 5	50-R1.5	*	0	38,533,317.45	18,746,808	19,786,509	5,022,130	13.03	3.9
	CANE RUN UNIT 5 SCRUBBER	50-R1.5	*	0	27,977,906.37	30,631,510	(2,653,604)	0	-	-
	CANE RUN UNIT 6	50-R1.5	*	0	56,536,729.43	27,194,785	29,341,944	7,454,271	13.18	3.9
	CANE RUN UNIT 6 SCRUBBER	50-R1.5	*	0	32,458,666.05	28,381,716	4,076,950	1,034,921	3.19	3.9
	MILL CREEK UNIT 1	50-R1.5	*	(14)	56,221,452.31	34,098,918	29,993,538	1,612,266	2.87	18.6
	MILL CREEK UNIT 1 SCRUBBER	50-R1.5	*	(14)	43,569,500.63	32,558,338	17,110,893	912,792	2.10	18.7
	MILL CREEK UNIT 2	50-R1.5	*	(14)	53,298,846.20	26,986,386	33,774,299	1,678,141	3.15	20.1
	MILL CREEK UNIT 2 SCRUBBER	50-R1.5	*	(14)	35,719,947.71	28,309,628	12,411,112	611,243	1.71	20.3
	MILL CREEK UNIT 3	50-R1.5	*	(14)	143,156,558.12	66,027,985	97,170,491	4,162,112	2.91	23.3
	MILL CREEK UNIT 3 SCRUBBER	50-R1.5	*	(14)	63,237,310.85	36,126,930	35,963,604	1,538,658	2.43	23.4
	MILL CREEK UNIT 4	50-R1.5	*	(14)	249,825,281.75	104,471,839	180,328,982	6,939,970	2.78	26.0
	MILL CREEK UNIT 4 SCRUBBER	50-R1.5	*	(14)	114,224,524.76	76,611,965	53,603,993	2,051,233	1.80	26.1
	TRIMBLE COUNTY UNIT 1	50-R1.5	*	(15)	217,217,963.01	74,259,062	175,541,595	5,798,005	2.67	30.3
	TRIMBLE COUNTY UNIT 1 SCRUBBER	50-R1.5	*	(15)	63,774,643.01	46,576,791	26,764,048	885,430	1.39	30.2
	TRIMBLE COUNTY UNIT 2	50-R1.5	*	(15)	121,585,784.34	4,866,329	134,957,323	3,107,492	2.56	43.4
	TRIMBLE COUNTY UNIT 2 SCRUBBER	50-R1.5	*	(15)	14,269,003.46	555,655	15,853,699	365,040	2.56	43.4
	TOTAL ACCOUNT 312 - BOILER PLANT EQUIPMENT				1,381,875,059.71	679,772,370	870,925,276	45,412,906	3.29	19.2
312.01	BOILER PLANT EQUIPMENT - LOCOMOTIVE									
	CANE RUN LOCOMOTIVE	25-R2.5	*	0	51,549.42	51,549	0	0	-	-
	MILL CREEK LOCOMOTIVE	25-R2.5	*	0	613,424.43	494,206	119,218	37,326	6.08	3.2
	TOTAL ACCOUNT 312.01 - BOILER PLANT EQUIPMENT - LOCOMOTIVE				664,973.85	545,755	119,218	37,326	5.61	3.2
312.02	BOILER PLANT EQUIPMENT - RAIL CARS									
	CANE RUN RAIL CARS	25-R2.5	*	0	1,501,772.81	1,161,405	340,368	103,455	6.89	3.3
	MILL CREEK RAIL CARS	25-R2.5	*	0	2,298,377.65	2,214,107	84,271	8,166	0.36	10.3
	TOTAL ACCOUNT 312.02 - BOILER PLANT EQUIPMENT - RAIL CARS				3,800,150.46	3,375,512	424,639	111,621	2.94	3.8

LOUISVILLE GAS AND ELECTRIC COMPANY
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	ACCOUNT	SURVIVOR CURVE		NET SALVAGE PERCENT	ORIGINAL COST	BOOK DEPRECIATION RESERVE	FUTURE ACCRUALS	CALCULATED ANNUAL ACCRUAL AMOUNT	CALCULATED ANNUAL ACCRUAL RATE	COMPOSITE REMAINING LIFE
	(1)	(2)		(3)	(4)	(5)	(6)	(7)	(8)=(7)/(4)	(9)=(6)/(7)
314.00	TURBOGENERATOR UNITS									
	CANE RUN UNIT 1	FULLY ACCRUED	*	0	106,008.99	116,610	(10,601)	0	-	-
	CANE RUN UNIT 2	FULLY ACCRUED	*	0	19,999.00	21,999	(2,000)	0	-	-
	CANE RUN UNIT 3	FULLY ACCRUED	*	0	581,177.00	639,295	(58,118)	0	-	-
	CANE RUN UNIT 4	60-S1.5	*	0	9,318,503.05	8,958,801	359,702	90,036	0.97	4.0
	CANE RUN UNIT 5	60-S1.5	*	0	7,931,771.74	7,826,617	105,155	26,289	0.33	4.0
	CANE RUN UNIT 6	60-S1.5	*	0	16,728,286.69	11,512,691	5,215,596	1,314,234	7.86	4.0
	MILL CREEK UNIT 1	60-S1.5	*	(14)	14,686,467.07	13,065,010	3,677,562	201,763	1.37	18.2
	MILL CREEK UNIT 2	60-S1.5	*	(14)	17,091,026.54	13,298,105	6,185,665	308,769	1.81	20.0
	MILL CREEK UNIT 3	60-S1.5	*	(14)	31,675,230.08	19,495,161	16,614,601	689,886	2.18	24.1
	MILL CREEK UNIT 4	60-S1.5	*	(14)	42,573,105.70	28,812,799	19,720,541	770,093	1.81	25.6
	TRIMBLE COUNTY UNIT 1	60-S1.5	*	(15)	57,000,938.71	22,348,217	43,202,863	1,311,533	2.30	32.9
	TRIMBLE COUNTY UNIT 2	60-S1.5	*	(15)	20,447,426.61	2,602,945	20,911,596	449,336	2.20	46.5
	TOTAL ACCOUNT 314 - TURBOGENERATOR UNITS				218,159,941.18	128,698,250	115,922,562	5,161,939	2.37	22.5
315.00	ACCESSORY ELECTRIC EQUIPMENT									
	CANE RUN UNIT 1	FULLY ACCRUED	*	0	1,883,656.22	2,072,022	(188,366)	0	-	-
	CANE RUN UNIT 2	FULLY ACCRUED	*	0	1,238,068.15	1,361,875	(123,807)	0	-	-
	CANE RUN UNIT 3	FULLY ACCRUED	*	0	766,540.94	843,195	(76,654)	0	-	-
	CANE RUN UNIT 4	55-S2	*	0	5,920,913.98	5,264,226	656,688	164,593	2.78	4.0
	CANE RUN UNIT 4 SCRUBBER	55-S2	*	0	987,949.00	1,086,744	(98,795)	0	-	-
	CANE RUN UNIT 5	55-S2	*	0	9,434,824.77	5,414,071	4,020,754	1,011,158	10.72	4.0
	CANE RUN UNIT 5 SCRUBBER	55-S2	*	0	2,216,498.98	2,438,149	(221,650)	0	-	-
	CANE RUN UNIT 6	55-S2	*	0	12,602,452.90	7,468,070	5,134,383	1,294,450	10.27	4.0
	CANE RUN UNIT 6 SCRUBBER	55-S2	*	0	2,199,914.33	2,419,906	(219,992)	0	-	-
	MILL CREEK UNIT 1	55-S2	*	(14)	15,688,648.70	8,807,564	9,077,496	484,211	3.09	18.7
	MILL CREEK UNIT 1 SCRUBBER	55-S2	*	(14)	5,541,695.00	6,317,532	0	0	-	-
	MILL CREEK UNIT 2	55-S2	*	(14)	7,415,271.51	5,475,168	2,978,242	156,250	2.11	19.1
	MILL CREEK UNIT 2 SCRUBBER	55-S2	*	(14)	4,505,053.40	5,135,761	0	0	-	-
	MILL CREEK UNIT 3	55-S2	*	(14)	15,049,879.17	13,392,025	3,764,837	182,523	1.21	20.6
	MILL CREEK UNIT 3 SCRUBBER	55-S2	*	(14)	2,531,773.00	2,886,221	0	0	-	-
	MILL CREEK UNIT 4	55-S2	*	(14)	24,032,537.03	17,602,916	9,794,176	419,766	1.75	23.3
	MILL CREEK UNIT 4 SCRUBBER	55-S2	*	(14)	5,864,978.52	5,812,660	873,416	38,030	0.65	23.0
	TRIMBLE COUNTY UNIT 1	55-S2	*	(15)	49,158,784.47	25,131,907	31,400,695	1,051,627	2.14	29.9
	TRIMBLE COUNTY UNIT 1 SCRUBBER	55-S2	*	(15)	2,736,920.00	2,325,798	821,660	27,869	1.02	29.5
	TRIMBLE COUNTY UNIT 2	55-S2	*	(15)	8,302,486.30	191,917	9,355,942	196,849	2.37	47.5
	TOTAL ACCOUNT 315 - ACCESSORY ELECTRIC EQUIPMENT				178,078,846.37	121,447,727	76,949,025	5,027,326	2.82	15.3

LOUISVILLE GAS AND ELECTRIC COMPANY
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	ACCOUNT	SURVIVOR CURVE		NET SALVAGE PERCENT	ORIGINAL COST	BOOK DEPRECIATION RESERVE	FUTURE ACCRUALS	CALCULATED ANNUAL ACCRUAL AMOUNT	CALCULATED ANNUAL ACCRUAL RATE	COMPOSITE REMAINING LIFE
	(1)	(2)		(3)	(4)	(5)	(6)	(7)	(8)=(7)/(4)	(9)=(6)/(7)
316.00	MISCELLANEOUS POWER PLANT EQUIPMENT									
	CANE RUN UNIT 1	FULLY ACCRUED	*	0	38,745.62	42,620	(3,874)	0	-	-
	CANE RUN UNIT 3	FULLY ACCRUED	*	0	11,664.48	12,831	(1,167)	0	-	-
	CANE RUN UNIT 4	45-R2.5	*	0	87,249.03	30,774	56,475	14,209	16.29	4.0
316.00	MISCELLANEOUS POWER PLANT EQUIPMENT, cont.									
	CANE RUN UNIT 4 SCRUBBER	45-R2.5	*	0	6,464.30	7,111	(647)	0	-	-
	CANE RUN UNIT 5	45-R2.5	*	0	96,972.33	39,551	57,421	14,435	14.89	4.0
	CANE RUN UNIT 5 SCRUBBER	45-R2.5	*	0	47,299.47	52,029	(4,730)	0	-	-
	CANE RUN UNIT 6	45-R2.5	*	0	2,930,864.12	1,399,447	1,531,417	387,121	13.21	4.0
	CANE RUN UNIT 6 SCRUBBER	45-R2.5	*	0	31,568.91	34,726	(3,157)	0	-	-
	MILL CREEK UNIT 1	45-R2.5	*	(14)	740,548.61	490,286	353,939	21,659	2.92	16.3
	MILL CREEK UNIT 2	45-R2.5	*	(14)	125,820.55	94,780	48,655	2,680	2.13	18.2
	MILL CREEK UNIT 3	45-R2.5	*	(14)	410,061.13	323,848	143,622	6,338	1.55	22.7
	MILL CREEK UNIT 4	45-R2.5	*	(14)	7,285,291.68	2,613,795	5,691,438	214,243	2.94	26.6
	MILL CREEK UNIT 4 SCRUBBER	45-R2.5	*	(14)	74,850.91	38,270	47,060	1,730	2.31	27.2
	TRIMBLE COUNTY UNIT 1	45-R2.5	*	(15)	2,917,559.67	1,204,753	2,150,441	76,345	2.62	28.2
	TRIMBLE COUNTY UNIT 2	45-R2.5	*	(15)	1,540,223.39	42,234	1,729,023	40,502	2.63	42.7
	TOTAL ACCOUNT 316 - MISCELLANEOUS POWER PLANT EQUIPMENT				16,345,184.20	6,427,055	11,795,916	779,262	4.77	15.1
	TOTAL STEAM PRODUCTION PLANT				**2,121,660,944.61**	**1,145,073,487**	**1,233,363,129**	**62,769,166**	**2.96**	

LOUISVILLE GAS AND ELECTRIC COMPANY
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	ACCOUNT	SURVIVOR CURVE		NET SALVAGE PERCENT	ORIGINAL COST	BOOK DEPRECIATION RESERVE	FUTURE ACCRUALS	CALCULATED ANNUAL ACCRUAL AMOUNT	CALCULATED ANNUAL ACCRUAL RATE	COMPOSITE REMAINING LIFE
	(1)	(2)		(3)	(4)	(5)	(6)	(7)	(8)=(7)/(4)	(9)=(6)/(7)
	HYDRAULIC PRODUCTION PLANT									
331.00	STRUCTURES AND IMPROVEMENTS									
	OHIO FALLS - NON-PROJECT	100-S2	*	(6)	65,796.14	38,867	30,877	1,031	1.57	29.9
	OHIO FALLS - PROJECT 289	100-S2	*	(6)	4,897,579.69	4,267,867	923,567	27,453	0.56	33.6
	TOTAL ACCOUNT 331 - STRUCTURES AND IMPROVEMENTS				4,963,375.83	4,306,734	954,444	28,484	0.57	33.5
332.00	RESERVOIRS, DAMS AND WATERWAY									
	OHIO FALLS - PROJECT 289	100-S2.5	*	(6)	11,690,251.61	1,705,082	10,686,585	316,944	2.71	33.7
	TOTAL ACCOUNT 332 - RESERVOIRS, DAMS AND WATERWAY				11,690,251.61	1,705,082	10,686,585	316,944	2.71	33.7
333.00	WATER WHEELS, TURBINES AND GENERATORS									
	OHIO FALLS - PROJECT 289	100-S2.5	*	(6)	19,945,213.62	915,731	20,226,195	607,747	3.05	33.3
	TOTAL ACCOUNT 333 - WATER WHEELS, TURBINES AND GENERATORS				19,945,213.62	915,731	20,226,195	607,747	3.05	33.3
334.00	ACCESSORY ELECTRIC EQUIPMENT									
	OHIO FALLS - PROJECT 289	80-S4	*	(6)	5,509,836.22	1,941,911	3,898,515	115,506	2.10	33.8
	TOTAL ACCOUNT 334 - ACCESSORY ELECTRIC EQUIPMENT				5,509,836.22	1,941,911	3,898,515	115,506	2.10	33.8
335.00	MISCELLANEOUS POWER PLANT EQUIPMENT									
	OHIO FALLS - NON-PROJECT	80-S1.5	*	(6)	25,458.41	3,717	23,269	741	2.91	31.4
	OHIO FALLS - PROJECT 289	80-S1.5	*	(6)	284,788.68	51,923	249,953	7,752	2.72	32.2
	TOTAL ACCOUNT 335 - MISCELLANEOUS POWER PLANT EQUIPMENT				310,247.09	55,640	273,222	8,493	2.74	32.2
336.00	ROADS, RAILROADS AND BRIDGES									
	OHIO FALLS - PROJECT 289	80-S4	*	(6)	29,930.61	17,806	13,920	734	2.45	19.0
	TOTAL ACCOUNT 336 - ROADS, RAILROADS AND BRIDGES				29,930.61	17,806	13,920	734	2.45	19.0
	TOTAL HYDRAULIC PRODUCTION PLANT				**42,448,854.98**	**8,942,904**	**36,052,881**	**1,077,908**	**2.54**	

LOUISVILLE GAS AND ELECTRIC COMPANY
ELECTRIC PLANT

TABLE 1. SUMMARY OF ESTIMATED SURVIVOR CURVES, NET SALVAGE, ORIGINAL COST, BOOK DEPRECIATION RESERVE AND CALCULATED ANNUAL DEPRECIATION RATES AS OF DECEMBER 31, 2011

	ACCOUNT	SURVIVOR CURVE		NET SALVAGE PERCENT	ORIGINAL COST	BOOK DEPRECIATION RESERVE	FUTURE ACCRUALS	CALCULATED ANNUAL ACCRUAL AMOUNT	CALCULATED ANNUAL ACCRUAL RATE	COMPOSITE REMAINING LIFE
	(1)	(2)		(3)	(4)	(5)	(6)	(7)	(8)=(7)/(4)	(9)=(6)/(7)
	OTHER PRODUCTION PLANT									
341.00	STRUCTURES AND IMPROVEMENTS									
	CANE RUN GT 11	55-R3	*	(5)	211,518.43	26,810	195,284	30,309	14.33	6.4
	ZORN AND RIVER ROAD GAS TURBINE	55-R3	*	(5)	8,241.14	8,653	0	0	-	-
	PADDY'S RUN GENERATOR 12	55-R3	*	(5)	64,113.35	52,586	14,733	2,270	3.54	6.5
	PADDY'S RUN GENERATOR 13	55-R3	*	(5)	2,158,698.12	754,202	1,512,431	79,434	3.68	19.0
	BROWN CT 5	55-R3	*	(5)	858,538.64	300,046	601,420	31,587	3.68	19.0
	BROWN CT 6	55-R3	*	(5)	105,977.86	34,594	76,683	4,459	4.21	17.2
	BROWN CT 7	55-R3	*	(5)	144,356.29	47,476	104,098	6,060	4.20	17.2
	TRIMBLE COUNTY CT 5	55-R3	*	(5)	1,555,655.08	486,383	1,147,055	57,271	3.68	20.0
	TRIMBLE COUNTY CT 6	55-R3	*	(5)	1,467,923.89	463,218	1,078,102	53,850	3.67	20.0
	TRIMBLE COUNTY CT 7	55-R3	*	(5)	2,083,698.13	533,540	1,654,343	75,232	3.61	22.0
	TRIMBLE COUNTY CT 8	55-R3	*	(5)	2,075,526.50	531,447	1,647,856	74,937	3.61	22.0
	TRIMBLE COUNTY CT 9	55-R3	*	(5)	2,137,402.33	541,181	1,703,091	77,448	3.62	22.0
	TRIMBLE COUNTY CT 10	55-R3	*	(5)	2,132,789.69	540,013	1,699,416	77,281	3.62	22.0
	TOTAL ACCOUNT 341 - STRUCTURES AND IMPROVEMENTS				15,004,439.45	4,320,149	11,434,512	570,138	3.80	20.1
342.00	FUEL HOLDERS, PRODUCERS AND ACCESSORIES									
	CANE RUN GT 11	45-R2.5	*	(5)	319,042.17	35,135	299,859	46,751	14.65	6.4
	ZORN AND RIVER ROAD GAS TURBINE	45-R2.5	*	(5)	23,433.81	17,418	7,188	964	4.11	7.5
	PADDY'S RUN GENERATOR 11	45-R2.5	*	(5)	9,237.57	9,699	0	0	-	-
	PADDY'S RUN GENERATOR 12	45-R2.5	*	(5)	21,667.08	15,410	7,340	1,134	5.23	6.5
	PADDY'S RUN GENERATOR 13	45-R2.5	*	(5)	2,255,338.17	785,083	1,583,022	85,785	3.80	18.5
	BROWN CT 5	45-R2.5	*	(5)	846,906.63	228,324	660,928	35,694	4.21	18.5
	BROWN CT 6	45-R2.5	*	(5)	403,060.13	49,527	373,686	22,234	5.52	16.8
	BROWN CT 7	45-R2.5	*	(5)	141,363.16	(48,742)	197,173	11,574	8.19	17.0
	TRIMBLE COUNTY CT 5	45-R2.5	*	(5)	97,996.90	31,005	71,892	3,707	3.78	19.4
	TRIMBLE COUNTY CT 6	45-R2.5	*	(5)	97,861.58	30,967	71,788	3,702	3.78	19.4
	TRIMBLE COUNTY CT PIPELINE	45-R2.5	*	(5)	1,998,390.62	645,679	1,452,631	68,823	3.44	21.1
	TRIMBLE COUNTY CT 7	45-R2.5	*	(5)	338,423.07	86,852	268,492	12,611	3.73	21.3
	TRIMBLE COUNTY CT 8	45-R2.5	*	(5)	337,096.18	86,511	267,440	12,562	3.73	21.3
	TRIMBLE COUNTY CT 9	45-R2.5	*	(5)	347,146.53	88,099	276,405	12,983	3.74	21.3
	TRIMBLE COUNTY CT 10	45-R2.5	*	(5)	361,860.02	90,772	289,181	13,575	3.75	21.3
	TOTAL ACCOUNT 342 - FUEL HOLDERS, PRODUCERS AND ACCESSORIES				7,598,823.62	2,151,739	5,827,025	332,099	4.37	17.5

LOUISVILLE GAS AND ELECTRIC COMPANY
ELECTRIC PLANT

TABLE 1. SUMMARY OF ESTIMATED SURVIVOR CURVES, NET SALVAGE, ORIGINAL COST, BOOK DEPRECIATION RESERVE AND CALCULATED ANNUAL DEPRECIATION RATES AS OF DECEMBER 31, 2011

	ACCOUNT (1)	SURVIVOR CURVE (2)		NET SALVAGE PERCENT (3)	ORIGINAL COST (4)	BOOK DEPRECIATION RESERVE (5)	FUTURE ACCRUALS (6)	CALCULATED ANNUAL ACCRUAL AMOUNT (7)	CALCULATED ANNUAL ACCRUAL RATE (8)=(7)/(4)	COMPOSITE REMAINING LIFE (9)=(6)/(7)
343.00	PRIME MOVERS									
	PADDY'S RUN GENERATOR 13	30-R2	*	(5)	20,146,190.99	5,644,307	15,509,194	944,090	4.69	16.4
	BROWN CT 5	30-R2	*	(5)	15,877,891.00	4,993,220	11,678,566	707,119	4.45	16.5
	BROWN CT 6	30-R2	*	(5)	19,951,721.96	2,379,308	18,570,000	1,220,599	6.12	15.2
	BROWN CT 7	30-R2	*	(5)	18,239,647.01	4,842,316	14,309,313	945,333	5.18	15.1
	TRIMBLE COUNTY CT 5	30-R2	*	(5)	16,268,197.67	4,216,785	12,864,823	730,006	4.49	17.6
	TRIMBLE COUNTY CT 6	30-R2	*	(5)	13,120,484.41	3,291,737	10,484,772	604,661	4.61	17.3
	TRIMBLE COUNTY CT 7	30-R2	*	(5)	13,611,692.25	3,670,974	10,621,303	563,209	4.14	18.9
	TRIMBLE COUNTY CT 8	30-R2	*	(5)	13,496,647.46	3,637,317	10,534,163	558,481	4.14	18.9
	TRIMBLE COUNTY CT 9	30-R2	*	(5)	13,407,237.42	3,476,963	10,600,636	561,647	4.19	18.9
	TRIMBLE COUNTY CT 10	30-R2	*	(5)	13,352,629.95	3,461,812	10,558,449	559,580	4.19	18.9
	TOTAL ACCOUNT 343 - PRIME MOVERS				157,472,340.12	39,614,739	125,731,219	7,394,725	4.70	17.0
344.00	GENERATORS									
	CANE RUN GT 11	60-S3	*	(5)	2,910,123.60	2,077,069	978,561	152,169	5.23	6.4
	ZORN AND RIVER ROAD GAS TURBINE	60-S3	*	(5)	1,827,580.88	1,918,960	0	0	-	-
	PADDY'S RUN GENERATOR 11	60-S3	*	(5)	1,523,115.56	1,599,271	0	0	-	-
344.00	GENERATORS, cont.									
	PADDY'S RUN GENERATOR 12	60-S3	*	(5)	2,991,589.41	3,141,169	0	0	-	-
	PADDY'S RUN GENERATOR 13	60-S3	*	(5)	5,859,857.93	2,327,573	3,825,278	196,875	3.36	19.4
	BROWN CT 5	60-S3	*	(5)	3,249,359.88	1,069,622	2,342,206	120,531	3.71	19.4
	BROWN CT 6	60-S3	*	(5)	2,417,994.54	893,368	1,645,526	94,354	3.90	17.4
	BROWN CT 7	60-S3	*	(5)	2,421,079.26	871,507	1,670,626	95,793	3.96	17.4
	TRIMBLE COUNTY CT 5	60-S3	*	(5)	1,539,295.24	483,419	1,132,841	55,449	3.60	20.4
	TRIMBLE COUNTY CT 6	60-S3	*	(5)	1,537,167.60	482,827	1,131,199	55,369	3.60	20.4
	TRIMBLE COUNTY CT 7	60-S3	*	(5)	1,726,823.88	439,138	1,374,027	61,258	3.55	22.4
	TRIMBLE COUNTY CT 8	60-S3	*	(5)	1,717,276.72	436,711	1,366,430	60,920	3.55	22.4
	TRIMBLE COUNTY CT 9	60-S3	*	(5)	1,728,008.37	434,500	1,379,909	61,521	3.56	22.4
	TRIMBLE COUNTY CT 10	60-S3	*	(5)	1,722,674.29	433,159	1,375,649	61,331	3.56	22.4
	TOTAL ACCOUNT 344 - GENERATORS				33,171,947.16	16,608,293	18,222,252	1,015,570	3.06	17.9
345.00	ACCESSORY ELECTRIC EQUIPMENT									
	CANE RUN GT 11	45-R3	*	(5)	116,627.22	122,459	0	0	-	-
	ZORN AND RIVER ROAD GAS TURBINE	45-R3	*	(5)	44,282.77	46,497	0	0	-	-
	PADDY'S RUN GENERATOR 11	45-R3	*	(5)	68,109.35	70,884	631	98	0.14	6.4
	PADDY'S RUN GENERATOR 12	45-R3	*	(5)	912,641.50	131,728	826,546	128,022	14.03	6.5
	PADDY'S RUN GENERATOR 13	45-R3	*	(5)	2,778,992.60	992,746	1,925,196	102,951	3.70	18.7
	BROWN CT 5	45-R3	*	(5)	2,588,422.56	920,956	1,796,888	96,071	3.71	18.7
	BROWN CT 6	45-R3	*	(5)	970,189.22	359,270	659,429	39,116	4.03	16.9
	BROWN CT 7	45-R3	*	(5)	953,200.45	349,815	651,045	38,646	4.05	16.8
	TRIMBLE COUNTY CT 5	45-R3	*	(5)	706,963.22	213,484	528,827	26,855	3.80	19.7
	TRIMBLE COUNTY CT 6	45-R3	*	(5)	1,594,892.41	447,269	1,227,368	62,428	3.91	19.7
	TRIMBLE COUNTY CT 7	45-R3	*	(5)	1,843,364.42	481,481	1,454,052	67,285	3.65	21.6
	TRIMBLE COUNTY CT 8	45-R3	*	(5)	1,836,141.17	479,594	1,448,354	67,022	3.65	21.6
	TRIMBLE COUNTY CT 9	45-R3	*	(5)	1,890,840.33	488,486	1,496,896	69,268	3.66	21.6
	TRIMBLE COUNTY CT 10	45-R3	*	(5)	4,387,836.09	977,530	3,629,698	167,932	3.83	21.6
	TOTAL ACCOUNT 345 - ACCESSORY ELECTRIC EQUIPMENT				20,692,503.31	6,082,199	15,644,930	865,694	4.18	18.1

LOUISVILLE GAS AND ELECTRIC COMPANY
ELECTRIC PLANT

TABLE 1. SUMMARY OF ESTIMATED SURVIVOR CURVES, NET SALVAGE, ORIGINAL COST, BOOK DEPRECIATION RESERVE AND CALCULATED ANNUAL DEPRECIATION RATES AS OF DECEMBER 31, 2011

	ACCOUNT	SURVIVOR CURVE		NET SALVAGE PERCENT	ORIGINAL COST	BOOK DEPRECIATION RESERVE	FUTURE ACCRUALS	CALCULATED ANNUAL ACCRUAL AMOUNT	CALCULATED ANNUAL ACCRUAL RATE	COMPOSITE REMAINING LIFE
	(1)	(2)		(3)	(4)	(5)	(6)	(7)	(8)=(7)/(4)	(9)=(6)/(7)
346.00	MISCELLANEOUS POWER PLANT EQUIPMENT									
	ZORN AND RIVER ROAD GAS TURBINE	50-S3	*	(5)	9,488.39	368	9,595	1,279	13.48	7.5
	PADDY'S RUN GENERATOR 11	50-S3	*	(5)	9,494.38	374	9,595	1,476	15.55	6.5
	PADDY'S RUN GENERATOR 13	50-S3	*	(5)	1,281,034.19	401,565	943,521	48,929	3.82	19.3
	BROWN CT 5	50-S3	*	(5)	2,395,225.12	815,731	1,699,255	88,126	3.68	19.3
	BROWN CT 6	50-S3	*	(5)	22,455.77	8,149	15,430	888	3.95	17.4
	BROWN CT 7	50-S3	*	(5)	23,047.78	8,142	16,058	924	4.01	17.4
	TRIMBLE COUNTY CT 5	50-S3	*	(5)	14,528.92	3,935	11,320	555	3.82	20.4
	TRIMBLE COUNTY CT 7	50-S3	*	(5)	5,204.51	1,298	4,167	187	3.59	22.3
	TRIMBLE COUNTY CT 8	50-S3	*	(5)	5,182.59	1,292	4,150	186	3.59	22.3
	TRIMBLE COUNTY CT 9	50-S3	*	(5)	5,328.44	1,315	4,280	192	3.60	22.3
	TRIMBLE COUNTY CT 10	50-S3	*	(5)	25,332.91	2,410	24,190	1,079	4.26	22.4
	TOTAL ACCOUNT 346 - MISCELLANEOUS POWER PLANT EQUIPMENT				3,796,323.00	1,244,579	2,741,561	143,821	3.79	19.1
	TOTAL OTHER PRODUCTION PLANT				**237,736,376.66**	**70,021,698**	**179,601,499**	**10,322,047**	**4.34**	
	TRANSMISSION PLANT									
350.10	LAND RIGHTS	60-R3		0	7,781,410.59	2,271,916	5,509,495	116,377	1.50	47.3
352.10	STRUCTURES AND IMPROVEMENTS	55-R1.5		(5)	6,456,555.13	1,500,856	5,278,527	112,155	1.74	47.1
353.10	STATION EQUIPMENT	55-R2.5		(10)	127,564,599.08	69,433,144	70,887,915	1,763,324	1.38	40.2
354.00	TOWERS AND FIXTURES	70-R3		(50)	40,070,495.05	22,555,849	37,549,894	688,232	1.72	54.6
355.00	POLES AND FIXTURES	53-R2		(55)	53,282,211.94	18,093,397	64,494,032	1,542,009	2.89	41.8
356.00	OVERHEAD CONDUCTORS AND DEVICES	50-R2		(40)	47,242,306.84	24,580,970	41,558,260	1,179,283	2.50	35.2
357.00	UNDERGROUND CONDUIT	55-R3		0	2,437,093.57	617,934	1,819,160	40,795	1.67	44.6
358.00	UNDERGROUND CONDUCTORS AND DEVICES	35-R3		(5)	5,659,798.38	2,183,949	3,758,839	168,808	2.98	22.3
	TOTAL TRANSMISSION PLANT				**290,494,470.58**	**141,238,015**	**230,856,122**	**5,610,983**	**1.93**	
	DISTRIBUTION PLANT									
361.00	STRUCTURES AND IMPROVEMENTS	50-L1.5		(10)	4,257,660.38	1,934,525	2,748,901	68,679	1.61	40.0
362.00	STATION EQUIPMENT	50-R1.5		(15)	106,268,031.32	37,506,516	84,701,720	2,221,197	2.09	38.1
364.00	POLES, TOWERS AND FIXTURES	50-R2.5		(70)	135,482,459.50	68,100,569	162,219,612	4,586,729	3.39	35.4
365.00	OVERHEAD CONDUCTORS AND DEVICES	50-R1.5		(60)	234,012,661.34	97,059,045	277,361,213	6,977,970	2.98	39.7
366.00	UNDERGROUND CONDUIT	70-R4		(20)	69,528,364.13	26,343,100	57,090,937	1,041,697	1.50	54.8
367.00	UNDERGROUND CONDUCTORS AND DEVICES	55-R3		(20)	145,471,542.41	48,421,476	126,144,375	2,797,549	1.92	45.1
368.00	LINE TRANSFORMERS	45-R3		(20)	140,346,229.93	63,165,088	105,250,388	3,341,572	2.38	31.5
369.10	SERVICES - UNDERGROUND	45-R2.5		(40)	6,152,801.50	1,616,005	6,997,917	204,433	3.32	34.2
369.20	SERVICES - OVERHEAD	50-R2		(100)	21,115,396.68	19,735,617	22,495,176	758,402	3.59	29.7
370.00	METERS	30-R2.5		0	37,655,788.09	19,907,329	17,748,459	1,099,191	2.92	16.1
373.10	STREET LIGHTING AND SIGNAL SYSTEMS - OVERHEAD	28-L0.5		(25)	34,508,233.24	12,877,300	30,257,992	1,368,855	3.97	22.1
373.20	STREET LIGHTING AND SIGNAL SYSTEMS - UNDERGROUND	35-R2		(30)	48,188,855.10	21,419,157	41,226,355	1,660,101	3.44	24.8
	TOTAL DISTRIBUTION PLANT				**982,988,023.62**	**418,085,727**	**934,243,045**	**26,126,375**	**2.66**	

LOUISVILLE GAS AND ELECTRIC COMPANY
ELECTRIC PLANT

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	ACCOUNT	SURVIVOR CURVE	NET SALVAGE PERCENT	ORIGINAL COST	BOOK DEPRECIATION RESERVE	FUTURE ACCRUALS	CALCULATED ANNUAL ACCRUAL AMOUNT	CALCULATED ANNUAL ACCRUAL RATE	COMPOSITE REMAINING LIFE
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)=(7)/(4)	(9)=(6)/(7)
	GENERAL PLANT								
392.10	TRANSPORTATION EQUIPMENT - CARS AND LIGHT TRUCKS	7-L2.5	0	1,570,997.82	1,071,980	499,018	86,083	5.48	5.8
392.20	TRANSPORTATION EQUIPMENT - TRAILERS	20-S1	5	607,413.67	257,488	319,555	37,747	6.21	8.5
392.30	TRANSPORTATION EQUIPMENT - HEAVY TRUCKS AND OTHER	14-S1.5	0	6,613,187.42	6,077,693	535,494	39,795	0.60	13.5
394.00	TOOLS, SHOP AND GARAGE EQUIPMENT	25-SQ	0	4,603,923.59	1,508,076	3,095,848	207,415	4.51	14.9
396.10	POWER OPERATED EQUIPMENT - SMALL MACHINERY	8-L2	0	1,292,580.47	1,292,580	0	0	-	-
396.20	POWER OPERATED EQUIPMENT - OTHER	17-L3	0	151,086.93	26,948	124,139	11,484	7.60	10.8
396.30	POWER OPERATED EQUIPMENT - LARGE MACHINERY	12-L1.5	0	1,110,684.81	925,971	184,714	23,551	2.12	7.8
	TOTAL GENERAL PLANT			**15,949,874.71**	**11,160,736**	**4,758,768**	**406,075**	**2.55**	
	TOTAL DEPRECIABLE PLANT			**3,691,278,545.16**	**1,794,522,567**	**2,618,875,444**	**106,312,554**	**2.88**	
	NONDEPRECIABLE PLANT								
301.00	ORGANIZATION			2,240.29					
310.20	LAND			6,193,327.37					
310.25	LAND			100,000.00					
330.20	LAND			6.50					
340.20	LAND			8,132.93					
350.20	LAND			1,573,048.99					
360.20	LAND			4,110,848.65					
	TOTAL NONDEPRECIABLE PLANT			**11,987,604.73**					
	TOTAL ELECTRIC PLANT			**3,703,266,149.89**	**1,794,522,567**	**2,618,875,444**	**106,312,554**		

* LIFE SPAN PROCEDURE IS USED. CURVE SHOWN IS INTERIM SURVIVOR CURVE

LOUISVILLE GAS AND ELECTRIC COMPANY

CASE NO. 2012-00222

Response to Commission Staff's Third Request for Information
Dated August 28, 2012

Question No. 33

Responding Witness: Lonnie E. Bellar

Q-33. Refer to LG&E's response to Item 83.b. of Staff's Second Request. Given that the response states that "physical curtailments would generally be necessary during times of high usage which usually results in relatively high market peak prices," explain whether it is still LG&E's position that its proposed Curtailable Service Rider credits are reasonable.

A-33. LG&E believes its proposed Curtailable Service Rider (CSR) credits are reasonable. KPSC 2-83(b) refers to the proposed CSR10 tariff which for a transmission voltage served customer would provide a credit of $2.75 per kVA-month. If you assume a customer has a unity (kW=kVA) power factor and the company physically interrupts the customer for the maximum of 100 hours in a year, the effective credit to the customer will be $330/MWh.[1] The maximum average of the 100 highest priced hours in the PJM and MISO markets on a rolling one year period from 2008 to August 2012 was $227/MWh.[2] While this simple example for a CSR10 customer does not consider the incremental value of the 275 hours of buy-through interruption and the benefit of being able to effect the physical interruption in 10 minutes, from an energy perspective the difference in the maximum market price and the calculated value demonstrates the reasonableness of the Companies' proposal.

[1] 2.75 $/kVA-month x 1,000 kVA/MW X 12 month/year = $33,000/MW-year => ($33,000/MW-year)/(100 hours/year) = $330/MWh.

[2] This value is derived by determining the maximum hourly price from the LG&E/KU interface with MISO (LGEE) and PJM (South Import) and calculating the described average.

LOUISVILLE GAS AND ELECTRIC COMPANY

CASE NO. 2012-00222

Response to Commission Staff's Third Request for Information
Dated August 28, 2012

Question No. 34

Responding Witness: Lonnie E. Bellar

Q-34. Refer to the response to Item 84 of Staff's Second Request. The second paragraph of the response refers to "the inputted avoided cost of gas supply." LG&E's gas Demand-Side Management ("DSM") tariff, Original Sheet No. 86.1, defines DSM Incentive program benefits as "the present value of Company's avoided costs over the expected life of the program, *and will include both capacity and energy savings*" (emphasis added). To the extent that the calculation of net resource benefits involves avoided cost of gas supply, provide an example calculation showing the components of capacity and energy savings, which could involve either LG&E's own Gas Cost Recovery rate or some other wholesale gas cost expressed in either dollars per Mcf or Ccf, or provide a specific reference to the location in volume 2 of the application in Case No. 2011-00134[3] where such a calculation is shown.

A-34. The DSM Incentive program benefits included in the current tariffs are based upon 5% of program costs as this is less than 15% of the net resource benefits. However, the calculation of the net resource benefits is based upon the avoided cost of gas supply imbedded in the company's DSMore model filed in case 2011-00134, Application Volume II. The DSMore gas supply curve represented 2011 Henry Hub NYMEX futures market prices. Attached is an example calculation of the DSM Incentive for the Residential Low-Income Weatherization Program.

[3] Case No. 2011-00134, Joint Application of Louisville Gas and Electric Company and Kentucky Utilities Company for Review, Modification, and Continuation of Existing, and Addition of New Demand-Side Management and Energy-Efficiency Programs (Ky. PSC Nov. 9, 2011).

2011 Program Modeled Output[4]

	DSMore Model Output For 2011	
	Lost Revenues, Costs, and Benefits	
		Today's Value
1	Lost Revenue (Electric)	$2,673,884
2	Lost Revenue (Gas)	$2,363,084
3	Total	$5,036,968
4		
5	Net Lost Revenue (Electric)	$1,892,935
6	Net Lost Revenue (Gas)	$628,310
7	Total	$2,521,245
8		
9	Avoided Electric Production with Adders	$1,603,645
10	Avoided T&D Electric	$0
11	Avoided Gas Production	$1,739,862
12	Avoided Gas Capacity	$0
13	Total	$3,343,507
14		
15	Cost-Based Avoided Electric Production	$1,603,645
16	Cost-Based Avoided Electric Capacity	$894,837
17	Total	$2,498,481
18		
19	Administration Costs	$217,454
20	Implementation / Participation Costs	$2,023,440
21	Incentives	$0
22	Other / Miscellaneous Costs	$127,568
23	Total	$2,368,462
24		
25	Participant Costs (net free)	$0
26		
27	Tax Savings Benefits	$0
28		
29	Arrears Reduced	$0
30		
31	Environmental Benefits	$0
32	Other Benefits	$0
33	Total	$0
34		
35	Avoided Electric Production with Adders	$1,938,500
36	Avoided T&D Electric	$0
37	Avoided Gas Production	$2,110,802
38	Avoided Gas Capacity	$0
39	Total	$4,049,301
40		
41	Cost-Based Avoided Electric Production	$1,938,500
42	Cost-Based Avoided Electric Capacity	$1,085,677
43	Total	$3,024,177
44		
45	Administration Costs	$217,454
46	Implementation / Participation Costs	$2,023,440
47	Incentives	$0
48	Other / Miscellaneous Costs	$127,568
49	Total	$2,368,462
50		
51	Participant Bill Savings (Electric)	$2,673,884
52	Participant Bill Savings (Gas)	$2,363,084
53	Total	$5,036,968
54		
55	Incentives	$0
56		
57	Total Program Costs per kW Saved	$213.38
58	Total Program Costs per kWh Saved	$178.16
59	Total Program Costs per CCF Saved	$4,454.33

[4] Volume II – Exhibit B of Case No. 2011-00134 contains the seven year program calculations in similar format to the annual values presented here.

DSMore Output Summary

	Residential WeCare	**2011**
	Values in thousand $$	
a	Avoided NG - (Row 11, 12)	$1,740
b	Avoided EL Prod (Row 9,10)	$1,604
c	Avoided EL Capacity (Row 16)	$895
d	Program Costs (Row 25,45,46,48)	($2,368)
	Gas Benefits (a)	**$1,740**
	Electric Benefits (b+c)	**$2,498**
	Total Costs (d)	**($2,368)**

DSM Mechanism - Incentive Calculation

Residential WeCare	Costs	Gas Benefits	Electric Benefits	Net Resource	15% Net Resource	5% Program Cost	DSM Incentive
Values in thousand $$							
Residential Electric - LGE	($457)	$0	$696	$239	$36	$23	$23
Residential Gas - LGE	($727)	$1,740	$0	$1,013	$152	$36	$36
Residential Electric - KU	($1,184)	$0	$1,803	$618	$93	$59	$59
Total	**($2,368)**	**$1,740**	**$2,498**	**$1,870**	**$280**	**$118**	**$118**

LOUISVILLE GAS AND ELECTRIC COMPANY

CASE NO. 2012-00222

Response to Commission Staff's Third Request for Information
Dated August 28, 2012

Question No. 35

Responding Witness: J. Clay Murphy

Q-35. Refer to the response to Item 85 of Staff's Second Request, the reference to Columbia's DS tariff. Explain whether LG&E is aware that there is no requirement for telemetry in Columbia's DS tariff for customers using 25,000 Mcf annually.

A-35. LG&E is aware that there is no requirement for telemetry in Columbia's DS tariff for customers using 25,000 Mcf annually.

However, Duke Energy Kentucky, Inc.'s Rate FT-L does require customers served thereunder to have remote metering. See also LG&E's response to Question No. 23.

LOUISVILLE GAS AND ELECTRIC COMPANY

CASE NO. 2012-00222

Response to Commission Staff's Third Request for Information
Dated August 28, 2012

Question No. 36

Responding Witness: Shannon L. Charnas / John J. Spanos

Q-36. Refer to the response to Item 94.e. of Staff's Second Request, which does not contain the requested information. Under Generally Accepted Accounting Principles, financial statements must report asset removal costs recovered through depreciation which are not Asset Retirement Obligations ("ARO") as a regulatory liability.

a. Provide the total amount of asset removal costs LG&E reported as a regulatory liability in its financial statements as of December 31, 2011.

b. Provide the total amount of AROs LG&E reported in its financial statements as of December 31, 2011.

c. Provide the regulatory liability reported as of December 31, 2011 that was accrued on the Cane Run units. Provide the workpapers demonstrating how the amounts were determined.

d. Provide the amount of AROs reported as of December 31, 2011 that were accrued on the Cane Run units. Provide the workpapers demonstrating how the amounts were determined

A-36. a. The total amount of asset removal costs LG&E reported as a regulatory liability as of December 31, 2011 was $286,215,127.

b. The total ARO liability LG&E reported as of December 31, 2011 was $56,856,461.

c. Per Title 18, Subchapter C – Accounts, Federal Power Act, Part 101 – Uniform System of Accounts prescribed for Public Utilities, account 108, accumulated provision for depreciation of utility plant, shall be regarded and treated as a single composite provision for depreciation, but shall be segregated by functional classification. Further detail by plant account is not required, but is calculated for ease of reporting. This calculation is simply an allocation of the total cost of removal and salvage reserve performed by the fixed asset system. The total amount of regulatory liability as of December 31, 2011 allocated as mentioned above for the Cane Run units was $19,735,832. See attached for the work paper.

d. The total ARO liability for the Cane Run units as of December 31, 2011 was $14,525,438. See attached for the work paper.

LOUISVILLE GAS & ELECTRIC COMPANY
REGULATORY LIABILITY FOR CANE RUN
DECEMBER 31, 2011

RESERVE TYPE	DEPRECIATION GROUP		REGULATORY LIABILITY
COST OF REMOVAL	LGE-131100-Cane Run Unit 1 Structures	$	306,825.77
SALVAGE	LGE-131100-Cane Run Unit 1 Structures		-
COST OF REMOVAL	LGE-131200-Cane Run Unit 1 Boiler		87,689.23
SALVAGE	LGE-131200-Cane Run Unit 1 Boiler		-
COST OF REMOVAL	LGE-131400-Cane Run Unit 1 Turbogenerator		33,546.50
SALVAGE	LGE-131400-Cane Run Unit 1 Turbogenerator		-
COST OF REMOVAL	LGE-131500-Cane Run Unit 1 Accessory Equipment		124,782.32
SALVAGE	LGE-131500-Cane Run Unit 1 Accessory Equipment		-
COST OF REMOVAL	LGE-131600-Cane Run Unit 1 Misc Power Plant Equipment		4,017.91
SALVAGE	LGE-131600-Cane Run Unit 1 Misc Power Plant Equipment		-
	TOTAL CANE RUN UNIT 1	$	556,861.73
COST OF REMOVAL	LGE-131100-Cane Run Unit 2 Structures	$	152,471.00
SALVAGE	LGE-131100-Cane Run Unit 2 Structures		-
COST OF REMOVAL	LGE-131200-Cane Run Unit 2 Boiler		25,455.46
SALVAGE	LGE-131200-Cane Run Unit 2 Boiler		-

RESERVE TYPE	DEPRECIATION GROUP		REGULATORY LIABILITY
COST OF REMOVAL	LGE-131400-Cane Run Unit 2 Turbogenerator		1,493.00
SALVAGE	LGE-131400-Cane Run Unit 2 Turbogenerator		-
COST OF REMOVAL	LGE-131500-Cane Run Unit 2 Accessory Equipment		20,484.99
SALVAGE	LGE-131500-Cane Run Unit 2 Accessory Equipment		403,041.77
	TOTAL CANE RUN UNIT 2	$	602,946.22
COST OF REMOVAL	LGE-131100-Cane Run Unit 3 Structures	$	252,726.43
SALVAGE	LGE-131100-Cane Run Unit 3 Structures		-
COST OF REMOVAL	LGE-131200-Cane Run Unit 3 Boiler		112,310.57
SALVAGE	LGE-131200-Cane Run Unit 3 Boiler		-
COST OF REMOVAL	LGE-131400-Cane Run Unit 3 Turbogenerator		42,526.00
SALVAGE	LGE-131400-Cane Run Unit 3 Turbogenerator		-
COST OF REMOVAL	LGE-131500-Cane Run Unit 3 Accessory Equipment		56,033.00
SALVAGE	LGE-131500-Cane Run Unit 3 Accessory Equipment		-
COST OF REMOVAL	LGE-131600-Cane Run Unit 3 Misc. Power Plant Equipment		738.00
SALVAGE	LGE-131600-Cane Run Unit 3 Misc. Power Plant Equipment		-
	TOTAL CANE RUN UNIT 3	$	464,334.00
COST OF REMOVAL	LGE-131100-Cane Run Unit 4 SO2-Structures	$	44,766.75
SALVAGE	LGE-131100-Cane Run Unit 4 SO2-Structures		-

RESERVE TYPE	DEPRECIATION GROUP	REGULATORY LIABILITY
COST OF REMOVAL	LGE-131100-Cane Run Unit 4 Structures	288,604.66
SALVAGE	LGE-131100-Cane Run Unit 4 Structures	(4,015.03)
COST OF REMOVAL	LGE-131200-CR Unit 4 Boiler	2,549,014.76
SALVAGE	LGE-131200-CR Unit 4 Boiler	(489,172.37)
COST OF REMOVAL	LGE-131200-CR Unit 4 Boiler ECR 2006	2,210.35
SALVAGE	LGE-131200-CR Unit 4 Boiler ECR 2006	(155.22)
COST OF REMOVAL	LGE-131200-Cane Run Unit 4 SO2 Boiler	1,025,987.79
SALVAGE	LGE-131200-Cane Run Unit 4 SO2 Boiler	(84,557.84)
COST OF REMOVAL	LGE-131400-Cane Run Unit 4 Turbogenerator	837,710.63
SALVAGE	LGE-131400-Cane Run Unit 4 Turbogenerator	(170,477.43)
COST OF REMOVAL	LGE-131500-Cane Run Unit 4 Accessory Equipment	417,521.45
SALVAGE	LGE-131500-Cane Run Unit 4 Accessory Equipment	(5,825.87)
COST OF REMOVAL	LGE-131500-Cane Run Unit 4 SO2 Accessory Equipment	69,607.75
SALVAGE	LGE-131500-Cane Run Unit 4 SO2 Accessory Equipment	-
COST OF REMOVAL	LGE-131600-Cane Run Unit 4 Misc. Power Plant Equipment	4,504.27
SALVAGE	LGE-131600-Cane Run Unit 4 Misc. Power Plant Equipment	(74.70)

RESERVE TYPE	DEPRECIATION GROUP		REGULATORY LIABILITY
COST OF REMOVAL	LGE-131600-Cane Run Unit 4 SO2 Misc Power Plant Equipment		480.70
SALVAGE	LGE-131600-Cane Run Unit 4 SO2 Misc Power Plant Equipment		-
	TOTAL CANE RUN UNIT 4	$	4,486,130.65
COST OF REMOVAL	LGE-131100-Cane Run Unit 5 SO2-Structures	$	162,172.28
SALVAGE	LGE-131100-Cane Run Unit 5 SO2-Structures		(1,526.76)
COST OF REMOVAL	LGE-131100-Cane Run Unit 5 Structures		515,675.03
SALVAGE	LGE-131100-Cane Run Unit 5 Structures		(6,476.96)
COST OF REMOVAL	LGE-131200-Cane Run Unit 5 SO2 Boiler		3,343,257.75
SALVAGE	LGE-131200-Cane Run Unit 5 SO2 Boiler		(435,840.38)
COST OF REMOVAL	LGE-131200-CR Unit 5 Boiler		1,099,373.81
SALVAGE	LGE-131200-CR Unit 5 Boiler		(287,091.78)
COST OF REMOVAL	LGE-131200-CR Unit 5 Boiler ECR 2006		1,443.44
SALVAGE	LGE-131200-CR Unit 5 Boiler ECR 2006		(189.72)
COST OF REMOVAL	LGE-131400-Cane Run Unit 5 Turbogenerator		773,747.92
SALVAGE	LGE-131400-Cane Run Unit 5 Turbogenerator		(185,079.90)
COST OF REMOVAL	LGE-131500-Cane Run Unit 5 Acccessory Equipment		347,651.90
SALVAGE	LGE-131500-Cane Run Unit 5 Acccessory Equipment		(7,241.76)

RESERVE TYPE	DEPRECIATION GROUP		REGULATORY LIABILITY
COST OF REMOVAL	LGE-131500-Cane Run Unit 5 SO2 Accessory Equipment		228,770.64
SALVAGE	LGE-131500-Cane Run Unit 5 SO2 Accessory Equipment		(1,994.85)
COST OF REMOVAL	LGE-131600-Cane Run Unit 5 Misc. Power Plant Equipment		3,817.07
SALVAGE	LGE-131600-Cane Run Unit 5 Misc. Power Plant Equipment		(84.87)
COST OF REMOVAL	LGE-131600-Cane Run Unit 5 SO2 Misc Power Plant Equipment		5,046.14
SALVAGE	LGE-131600-Cane Run Unit 5 SO2 Misc Power Plant Equipment		(42.57)
	TOTAL CANE RUN UNIT 5	$	5,555,386.43
COST OF REMOVAL	LGE-131100-Cane Run Unit 6 SO2-Structures	$	171,666.13
SALVAGE	LGE-131100-Cane Run Unit 6 SO2-Structures		(1,705.41)
COST OF REMOVAL	LGE-131100-CR Unit 6 Structures		1,379,175.90
SALVAGE	LGE-131100-CR Unit 6 Structures		(17,059.72)
COST OF REMOVAL	LGE-131100-CR Unit 6 Structures ECR 2005		32,283.26
SALVAGE	LGE-131100-CR Unit 6 Structures ECR 2005		-
COST OF REMOVAL	LGE-131110-CR 6 Capital Leased Equipment		118.50
SALVAGE	LGE-131110-CR 6 Capital Leased Equipment		-
COST OF REMOVAL	LGE-131200-CR Unit 6 Boiler		2,831,041.66
SALVAGE	LGE-131200-CR Unit 6 Boiler		(730,588.77)

RESERVE TYPE	DEPRECIATION GROUP	REGULATORY LIABILITY
COST OF REMOVAL	LGE-131200-CR Unit 6 Boiler ECR 2006	2,289.47
SALVAGE	LGE-131200-CR Unit 6 Boiler ECR 2006	(150.06)
COST OF REMOVAL	LGE-131200-CR6 SO2 Boiler	3,017,851.14
SALVAGE	LGE-131200-CR6 SO2 Boiler	(500,981.25)
COST OF REMOVAL	LGE-131200-CR6 SO2 Boiler ECR 2005	5,501.51
SALVAGE	LGE-131200-CR6 SO2 Boiler ECR 2005	(171.96)
COST OF REMOVAL	LGE-131400-Cane Run Unit 6 Turbogenerator	1,173,421.79
SALVAGE	LGE-131400-Cane Run Unit 6 Turbogenerator	(270,766.13)
COST OF REMOVAL	LGE-131500-Cane Run Unit 6 Accessory Equipment	571,962.86
SALVAGE	LGE-131500-Cane Run Unit 6 Accessory Equipment	(8,042.56)
COST OF REMOVAL	LGE-131500-Cane Run Unit 6 SO2 Accessory Equipment	221,920.02
SALVAGE	LGE-131500-Cane Run Unit 6 SO2 Accessory Equipment	(1,912.23)
COST OF REMOVAL	LGE-131501-AROP Cane Run 6 Accessory Equipment	0.01
SALVAGE	LGE-131501-AROP Cane Run 6 Accessory Equipment	-
COST OF REMOVAL	LGE-131600-Cane Run Unit 6 Misc. Power Plant Equipment	164,346.94
SALVAGE	LGE-131600-Cane Run Unit 6 Misc. Power Plant Equipment	(2,783.54)

RESERVE TYPE	DEPRECIATION GROUP		REGULATORY LIABILITY
COST OF REMOVAL	LGE-131600-Cane Run Unit 6 SO2 Misc. Power Plant Equipment		3,438.60
SALVAGE	LGE-131600-Cane Run Unit 6 SO2 Misc. Power Plant Equipment		(28.44)
	TOTAL CANE RUN UNIT 6	$	8,040,827.72
COST OF REMOVAL	LGE-131200-Cane Run Locomotives	$	3,348.01
SALVAGE	LGE-131200-Cane Run Locomotives		(601.30)
COST OF REMOVAL	LGE-131200-Cane Run Rail Cars		49,375.16
SALVAGE	LGE-131200-Cane Run Rail Cars		(22,776.95)
	TOTAL CANE RUN LOCOMOTIVES & RAIL CARS	$	29,344.92
	TOTAL CANE RUN	$	19,735,831.67

LOUISVILLE GAS & ELECTRIC COMPANY
ASSET RETIREMENT OBLIGATION LIABILITY
CANE RUN
DECEMBER 31, 2011

ARO DESCRIPTION	BALANCE 12/31/2011
Cane Run Ash Pond	$ 5,329,415.72
Cane Run Coal Storage	267,777.39
Cane Run Environmental Ponds	678,289.23
Cane Run Floodwall Penetration	1,101,827.06
Cane Run Generating Wells	152,675.14
Cane Run Landfill	2,340,875.52
Cane Run Nuclear Sources	43,399.13
Cane Run Unit 1 (Retired)-Asbestos	845,906.99
Cane Run Unit 2 (Retired)-Asbestos	796,868.87
Cane Run Unit 3 (Retired)-Asbestos	898,009.95
Cane Run Unit 4-Asbestos	937,569.99
Cane Run Unit 5-Asbestos	656,887.42
Cane Run Unit 6-Asbestos	475,935.21
TOTAL CANE RUN	$ 14,525,437.62

LOUISVILLE GAS AND ELECTRIC COMPANY

CASE NO. 2012-00222

Response to Commission Staff's Third Request for Information
Dated August 28, 2012

Question No. 37

Responding Witness: John J. Spanos

Q-37. Refer to pages III-4 and III-5 of Exhibit JJS-LG&E to the Spanos Testimony. In this proceeding, LG&E has determined that actual net salvage for the Cane Run units is equal to negative 10 percent of their original costs. Explain why LG&E estimates the net salvage to be more than negative 10 percent for each Steam Production Plant Unit listed on these pages.

A-37. The net salvage estimates as shown on pages III-4 and III-5 include components for both terminal net salvage and interim net salvage. The terminal net salvage estimates are negative 10 percent, while the interim net salvage estimates vary by plant account. The development of the composite estimates shown on pages III-4 and III-5 can be found on pages III-355 through III-356 of the depreciation study.

LOUISVILLE GAS AND ELECTRIC COMPANY

CASE NO. 2012-00222

Response to Commission Staff's Third Request for Information
Dated August 28, 2012

Question No. 38

Responding Witness: Shannon L. Charnas / John J. Spanos

Q-38. Refer to page III-5 of Exhibit JJS-LG&E to the Spanos Testimony, page III-5 of the depreciation study attached to the testimony submitted by Mr. Spanos in Case No. 2007-00564,[5] and Exhibit 8 of the Settlement Agreement filed by LG&E on January 13, 2009 in Case No. 2007-00564.

a. State whether LG&E has used the depreciation rates in Exhibit 8 of the Settlement Agreement to calculate its depreciation accruals since the Commission's approval of the Settlement Agreement.

b. If the response to part a. of this request is affirmative, explain why the book depreciation reserve shown on page III-5 of Exhibit JJS-LG&E for account 316, Cane Run Unit as of December 31, 2011, includes a negative 10 percent net salvage accrual when the net salvage assigned to this account on page III-5 of the depreciation study filed in Case No. 2007-00564 was negative 5 percent, which formed the basis for the depreciation rates included in the Settlement Agreement.

A-38. a. LG&E has used the depreciation rates from the Settlement Agreement to calculate its annual depreciation accruals since the approval of the Settlement Agreement.

b. For certain generating units that were either retired or approaching retirement, the reserve position at the date of the depreciation study was either too low (and thus required to be recovered over a short period of time), or exceeded the original cost of plant in service less net salvage. For example, for Account 316, the Cane Run scrubber for Unit 5 had a book reserve of $73,865 and an original cost amount of $47,299. In order to better match the book reserve with the depreciable lives and expected net salvage for these units, reserve amounts were transferred between these and other units within the same

[5] Case No. 2007-00564, Application of Louisville Gas and Electric Company to File a Depreciation Study (Ky. PSC Feb. 5, 2009).

FERC account. The transferred amounts will be recovered over the remaining lives of the other units.

It is not uncommon for reserves to be out of balance with the original cost for certain production plant units, due both to changing circumstances (e.g. early retirements), and to regulatory lag. The treatment in the depreciation study of rebalancing the reserve with transfers within each FERC account is a common and accepted practice in the industry.

LOUISVILLE GAS AND ELECTRIC COMPANY

CASE NO. 2012-00222

Response to Commission Staff's Third Request for Information
Dated August 28, 2012

Question No. 39

Responding Witness: Robert M. Conroy

Q-39. Refer to the response to Item 96.d. of Staff's Second Request.

a. Explain whether Interchange Out energy has been, and is currently, included with intersystem sales as indicated on Form A, page 3 of 5, section B, the first row titled "Inter-system Sales including interchange-out".

b. State whether the response indicates that:

1) The individual monthly Interchange In and Interchange Out energy amounts are not available;

2) Only the net Interchange energy amount is available and LG&E is requesting to include that amount with Purchases under section A on page 3 of Form A; and

3) Under LG&E's proposal, the titles on page 3 of the Form A would need to change to show net Interchange energy is included in Purchases in section A and to delete "including interchange-out" after "Inter-system Sales" in section B of the form.

A-39. a. No.

b. 1) Individual monthly Interchange In and Interchange Out energy amounts are not available.

2) Yes.

3) No. The titles refer to "Interchange In" and "Interchange Out," which include purchases and inter-system sales. LG&E does not think a change to the titles is necessary if its proposed change to the FAC is approved.

LOUISVILLE GAS AND ELECTRIC COMPANY

CASE NO. 2012-00222

Response to Commission Staff's Third Request for Information
Dated August 28, 2012

Question No. 40

Responding Witness: Robert M. Conroy

Q-40. Refer to the response to Item 108 of Staff's Second Request, the revised electric billing determinants in Exhibit R5, pages 1-14, Excel spread sheet for Conroy Exhibit R5, Time of Day Secondary Service Rate CTODS, Adjustment to Reflect Rate Switching to CTODS, rows 236 through 238 under column D. Explain why it is correct to use 81,741 kVA for the base, intermediate, and peak demand adjustments rather than the kVA for the three adjustments totaling 81,741.

A-40. Rate TOD-S demand rate design uses a "layered" rate design. The intermediate period is inclusive of the peak period and the base period is inclusive of the intermediate. Therefore, if a customer's highest demand reading for the billing period occurs during the peak period, then the customer pays the peak rate, the intermediate rate and base rate on the same demand reading. The purpose of this type of rate design is to provide an economic incentive to shift load from the peak period, since doing so results in a lower demand charge. For the purposes of the rate switching adjustment, the customers that moved to Rate CTOD-S and ITOD-S had not been on time-differentiated demand rates. LG&E made an assumption that the actual (or calculated in the case of GS customers) demands billed occurred during the peak period, which results in all three demand rates being charged to the total demands.

LOUISVILLE GAS AND ELECTRIC COMPANY

CASE NO. 2012-00222

Response to Commission Staff's Third Request for Information
Dated August 28, 2012

Question No. 41

Responding Witness: Robert M. Conroy

Q-41. Refer to the response to Item 108 of Staff's Second Request, the revised gas billing determinants in the Exhibit R10-Summary of IncreaseREV Excel spread sheet for Conroy Exhibit R10. Provide the calculation of $332,763 in Miscellaneous Revenues in cell B32.

A-41. The calculation of the Miscellaneous Revenues in cell B32 is as follows:

Rent from Electric/Gas Property	$232,767
Miscellaneous Service Revenues	91,420
Other Gas Revenue	8,576
Total	$332,763

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LOUISVILLE GAS AND ELECTRIC COMPANY

CASE NO. 2012-00222

Response to Commission Staff's Third Request for Information
Dated August 28, 2012

Question No. 42

Responding Witness: Robert M. Conroy

Q-42. Refer to the response to Item 108 of Staff's Second Request, the revised gas billing determinants in the Exhibit R11-Proposed Increase DetREV Excel spread sheet for Conroy Exhibit R11. Explain the composition of the proposed Billing Adjustments at present rates in row 15 in the amount of ($19,383); and in row 46 in the amount of ($3,102).

A-42. The Billing Adjustments are shown in rows 15 and 46 on Conroy Exhibit R11 are composed of prorated monthly bills for customers that come on or off the system during the month and corrections of billing errors.

LOUISVILLE GAS AND ELECTRIC COMPANY

CASE NO. 2012-00222

Response to Commission Staff's Third Request for Information
Dated August 28, 2012

Question No. 43

Responding Witness: Robert M. Conroy

Q-43. Refer to the response to Item 112 of Staff's Second Request. The response states that the Supplemental/Standby Service charge had previously been adjusted based on the proposed changes to demand charges but that, in this case, LG&E used cost based charges. Explain the reason for the change.

A-43. LG&E's previous Supplemental/Stand-by rates were developed by applying a percentage increase that approximately reflected the increase in the large power schedule under which a supplemental or standby customer would take service.

LG&E currently does not serve any customers under this rider. Therefore, the Company concluded that it would be more appropriate to adjust the rate to reflect the full cost of providing service without resulting in billing increases to any customers. In other words, at this point in time, the rate can be adjusted without a customer experiencing a large billing increase; therefore, the cost of service principle of gradualism should not be followed, in this instance, because no customers would be affected by the change.

LOUISVILLE GAS AND ELECTRIC COMPANY

CASE NO. 2012-00222

Response to Commission Staff's Third Request for Information
Dated August 28, 2012

Question No. 44

Responding Witness: Robert M. Conroy

Q-44. Refer to the response to Item 113 of Staff's Second Request. Explain what LG&E believes to be the reason(s) for the lack of customer participation in Rate RTP.

A-44. Real Time Pricing was presented to all eligible customers. Most of those customers discarded any interest immediately, although there were a few customers who requested additional information before rejecting the use of Rate RTP.

The negative response revolved around the need to monitor and control loads to realize any savings. Administratively for the customer, Rate RTP required more time and an expertise with which the customer felt uncomfortable. In addition, the savings which the customer could achieve from the reduction in billing for electric service would not off-set the other anticipated costs for the customer to comply with Rate RTP.

LOUISVILLE GAS AND ELECTRIC COMPANY

CASE NO. 2012-00222

Response to Commission Staff's Third Request for Information
Dated August 28, 2012

Question No. 45

Responding Witness: Robert M. Conroy

Q-45. Refer to the response to Item 114 of Staff's Second Request.

a. In reference to Item 114.a., explain whether the level of rate switching experienced by LG&E during the test year is significantly greater than in the past. The response should include the level of switching experienced in the last five years.

b. Refer to the response to Item 114.d. and the revised Exhibit P5 Excel spread sheet, page 7 of 8. Explain why cell C228, Actual Number of Customers for the 13-Month Period for Residential Customers including VFD and former RRP, is not calculated by the sum of cells B5 through B10, as opposed to cell F228 being the sum of cells B5 through B10. It appears that cell C228 should be 4,572,488 and that cell F228 should be the sum of cells C228, D228, and E228, for a total of 4,572,285 customers after rate switching. If a correction is necessary, provide a revised Exhibit P5 and revisions of all exhibits that would be affected by this change.

c. Refer to the response to Item 114.e., revised Exhibit P5 Excel spread sheet, page 7 of 8. Provide the response requested in b. above for cells H228 and K228, concerning the appropriate cell for the sum of Actual Energy Delivery for the 13-month period, cells F8 through F10.

A-45. a. The level of rate switching is only available beginning in April 2009 with the implementation date of LG&E's Customer Care System ("CCS"). The enhanced database and query opportunities available with CCS allow LG&E to track customer movements to a degree not previously possible. See the table below for the number of customers who moved from one rate to another rate by month for the period April 2009 through March 2011. LG&E believes that as customers become increasingly aware of the rate options available, they are initiating rate switching when such a move results in economic benefit.

	Rate Switching
APR 2009	25
MAY 2009	19
JUN 2009	23
JUL 2009	41
AUG 2009	32
SEP 2009	24
OCT 2009	20
NOV 2009	44
DEC 2009	40
JAN 2010	22
FEB 2010	55
MAR 2010	20
APR 2010	55
MAY 2010	45
JUN 2010	45
JUL 2010	45
AUG 2010	57
SEP 2010	40
OCT 2010	68
NOV 2010	62
DEC 2010	42
JAN 2011	71
FEB 2011	51
MAR 2011	70

b. Cells B5 through B10 include the impact of rate switching. The formulae for these cells use lookup functions to count the number of customers on the rates for each month of the 13-month period, and then add or subtract the number of customer-months reflecting the rate switching adjustment, as provided in cells X5 through Y10 (for customers leaving the rate) and W5 through W10 (for customers moving to the rate). Since the customer counts in cells B5 though B10 are already adjusted for rate switching, it is necessary to us the sum of cells B5 through B10 in cell F228, and remove the impact of rate switching to present the customers actually on the rate for the 13-month period in cell C228.

c. See response to part b. Cells F5 through F10 include the energy impact of rate switching, as identified in cells AA5 through AB10.

LOUISVILLE GAS AND ELECTRIC COMPANY

CASE NO. 2012-00222

Response to Commission Staff's Third Request for Information
Dated August 28, 2012

Question No. 46

Responding Witness: Robert M. Conroy

Q-46. Refer to the response to 118 of Staff's Second Request.

a. The response to Item 118.a. states that the "Annualized FAC roll-in to base rates" amount was allocated to each rate class based on the "calculated difference in FAC revenues on Conroy Exhibit P2, page 3 of 3." Explain why it would not have been more appropriate to use, for each rate class, the net difference between the "Twelve Month Total" column on Conroy Exhibit P2, page 3 of 3, and the "Increased Revenue" column on Conroy Exhibit P1, page 1 of 24, given that the total of the two columns net to the total being allocated of $3,930,286.

b. Refer to the response to Item 118.c. of Staff's Second Request, and to the response of KU to Item 88.d. of Staff's Second Request for Information in Case No. 2012-00221.[6] KU's response indicates that the two allocation vectors are the same, but that the naming convention was not synchronized. Clarify whether LG&E's response to 118c should be the same as KU's response to 88.d.

A-46. a. LG&E believes that the method it used and the method suggested by Staff will both yield reasonable results. LG&E used the method that has consistently been used in previous cost of service studies.

b. No. KU's response to PSC 2-88d should read: "KU's allocation vector FAC01 is the change in base rates from Conroy Exhibit P1. LG&E's allocation vector REV01 is the change in FAC revenues from Conroy Exhibit P2, page 3 of 3. The difference in allocation methods is a carry-over from an earlier version of the spreadsheet models that does not have a material impact on the results of the studies."

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[6] Case No. 2012-00221, Application of Kentucky Utilities Company for an Adjustment of Its Electric Rates, filed July 10, 2012.

LOUISVILLE GAS AND ELECTRIC COMPANY

CASE NO. 2012-00222

Response to Commission Staff's Third Request for Information
Dated August 28, 2012

Question No. 47

Responding Witness: Robert M. Conroy

Q-47. Refer to Item 123 of Staff's Second Request. Explain the impact of using the As Adjusted Demands as LG&E agrees the Cost-of-Service Study should have done, as opposed to the demand numbers used by LG&E. Provide corrected exhibits if correction is warranted.

A-47. See attachment being provided in Excel format for corrected Conroy Exhibit C10 and Conroy Exhibit R7, contained in the original electronic filing as "Att-PSC2-108-File05". The change from unadjusted to adjusted demands had no impact on the returns for RGS or CGS and had negligible impact on the returns for IGS, AAGS or FT. The most significant impact was in the return for Special Contracts. The change also impacted the Demand Related High Pressure per Unit Cost presented in Conroy Exhibit R7 by increasing it $.0002. Below are tables illustrating the impact on classes that experienced a change using the As Adjusted Demands in the Cost of Service Study:

PRO FORMA RATE OF RETURN				
	IGS	AAGS	FT	Special Contracts
Original	15.81%	16.69%	48.63%	41.30%
Revised	15.83%	16.83%	48.50%	48.67%
Difference	.02%	.14%	(.13%)	7.37%

PROPOSED RATE OF RETURN				
	IGS	AAGS	FT	Special Contracts
Original	19.30%	20.02%	53.51%	43.73%
Revised	19.32%	20.17%	53.38%	51.44%
Difference	.02%	.15%	(.13%)	7.71%

One attachment is being provided in a separate file in Excel format.

LOUISVILLE GAS AND ELECTRIC COMPANY

CASE NO. 2012-00222

Response to Commission Staff's Third Request for Information
Dated August 28, 2012

Question No. 48

Responding Witness: Robert M. Conroy

Q-48. Refer to Item 125 of Staff's Second Request. Considering the fact that the installed cost for the indicated light has not changed, explain the reasonableness of the proposed increase of the $13.99 rate, and generally for all lights whose rates are increasing due to the consolidation of lighting rate schedules, for customers affected by these rate increases.

A-48. The statement that "the installed cost for the indicated light has not changed" is incorrect. The installed cost of both LS, Lighting Service, and RLS, Restricted Lighting Service, changes with every fixture, pole, etc. that must be replaced due to failure or accidents.

LG&E applies the cost of service principle of gradualism when determining the appropriate increase to request for specific customer classes and when designing rates for its rate classes as a whole. It is not feasible to employ this principle on an individual customer basis. Specifically in regards to its lighting rates, LG&E is seeking in this proceeding to simplify its lighting options, clarify the circumstances under which lights may be installed, and specify which lights that are currently in service may not be installed in new locations. This process resulted in combining similar lights under one rate, and of necessity, some lighting types are proposed to receive larger increases than proposed for the lighting group as a whole. LG&E believes the simplified tariff schedules and increased clarity resulting from its proposals are of general benefit to its customers. Furthermore, for consistency the Company is attempting to adjust its rates in order to charge equivalent charges for equivalent services and similar charges for similar services.

LOUISVILLE GAS AND ELECTRIC COMPANY

CASE NO. 2012-00222

Response to Commission Staff's Third Request for Information
Dated August 28, 2012

Question No. 49

Responding Witness: Robert M. Conroy

Q-49. Refer to Item 126 of Staff's Second Request. Confirm that all of the items shown on Conroy Exhibit R8 are costs currently incurred at the level shown, including the Eagle Talon Data Acquisition System.

A-49. Confirmed.

LOUISVILLE GAS AND ELECTRIC COMPANY

CASE NO. 2012-00222

Response to Commission Staff's Third Request for Information
Dated August 28, 2012

Question No. 50

Responding Witness: Robert M. Conroy

Q-50. Refer to the response to Item 127 of Staff's Second Request.

a. Provide a definition of "levelized carrying charge" and "non-levelized carrying charge."

b. Explain whether LG&E is familiar with the Commission's clarification of Administrative Case 251[7] in Case No. 2000-00359[8] in which the Commission found that calculation of CATV charges should use either net pole costs or a rate of return adjusted for the ratio of net plant to gross plant applied to the gross average pole costs. If yes, explain how LG&E's calculation complies with the methodology set out in Case No. 2000-00359.

A-50. a. A *levelized carrying charge* is a uniform series of payments calculated by applying a uniform series capital recovery factor to the gross original cost investment. A capital recovery factor is equal to the rate of return plus sinking fund depreciation. The calculation of a levelized carrying charge is identical to the calculation of a conventional mortgage payment on a home. In calculating a levelized carrying charge (or a mortgage payment), a capital recovery factor is applied to the original, un-depreciated investment ("gross investment"). Without considering income taxes, a levelized carrying charge (LCC) is therefore calculated by applying the return on investment (ROR) plus the sinking fund depreciation to the gross investment as follows:

$$LCC = Gross\ Investment\ x\ [ROR + Sinking\ Fund\ Depreciation\ Rate]$$

Mathematically, it is not appropriate to apply a capital recovery factor (which

[7] Administrative Case 251, The Adoption of a Standard Methodology for Establishing Rates for CATV Pole Attachments (Ky. PSC Sept. 17, 1982).

[8] Case No. 2000-00359, Application of Cumberland Valley Electric, Inc. to Adjust Its Rates (Ky. PSC Feb. 26, 2001).

is equal to the rate of return plus sinking fund depreciation) to the depreciated investment ("net investment"). In the context of the proposed CATV attachment charge, applying a capital recovery factor – which reflects *sinking fund depreciation* as opposed to *straight line depreciation* – to net investment would result in a significant under-recovery of costs and would thus inappropriately shift these costs onto other customers.

A *non-levelized carrying charge* (NLCC) is a non-uniform series of payments calculated by applying the rate of return to net investment and then adding straight-line depreciation, as follows:

$$NLCC = Net\ Investment\ x\ ROR + Straight\ Line\ Depreciation$$

A non-levelized carrying charge calculation corresponds to the methodology used to determine revenue requirements in a rate case. Importantly, in a rate case *straight line depreciation* rather than *sinking fund depreciation* is used to calculate revenue requirements.

On a present value basis, levelized carrying charges are equivalent to non-levelized carrying charges over the life of the investment. This can be seen in the following attachment (Table I) which compares the present-value non-levelized carrying charges on a $1,000 investment to the present-value levelized carrying charges on the same $1,000 investment. Please note that for both calculations, the sum of the present value revenue carrying charges is equal to the original $1,000 investment.

But if sinking fund depreciation rather than straight-line depreciation is applied to the net investment then an incorrect result is obtained. As seen in Table II, calculating carrying charges by applying a *sinking fund depreciation* rate to the *net investment* results in significant under-recovery of carrying costs. When the levelized and non-levelized carrying charges are properly calculated, the sum of the present-value carrying charges for each series is equal to $1,000. But when sinking fund depreciation is applied to net investment, the sum of the present value carrying charges is only equal to $707.90. What this means is that if carrying charges are miscalculated in this manner, only 70.79% of cost will be recovered over the life of the investment.

The conclusion reached is that either methodology – either a levelized fixed charge calculation or non-levelized fixed charge calculation – is reasonable assuming that the methodologies are properly applied *and* assuming that the same methodology is consistently applied over time. While on a present value basis both methodologies will yield the same result over the life of the investment, during any particular year the carrying charges will likely be different. For this reason, generally it is not appropriate to switch back and forth between the two methodologies. While LG&E does not have a fundamental objection with using a non-levelized carrying charge calculation to determine CATV attachment charges *as long as straight-line depreciation is used in the calculation*, the Company does not believe that it is appropriate to switch back and forth between the two methodologies.

The use of levelized versus non-levelized carrying charge rates has been considered extensively by the Federal Energy Regulatory Commission ("FERC"). The FERC will allow the application of the levelized carrying charge rate (with sinking fund depreciation) to gross plant – which it calls the "levelized gross plant method" – or the application of a non-levelized carrying charge rate (with straight-line depreciation) to net plant – which it calls "nonlevelized net plant method". The FERC however, is reluctant to allow a utility to switch back and forth between the two methodologies. In a series of cases involving levelized carrying charges, the FERC rejected attempts to switch from a "net plant" approach to a "levelized" approach in midstream, finding that "allowing Consumers to switch pricing methodologies from the nonlevelized approach … to the levelized approach … is inappropriate." *Consumers Energy Co., Opinion No. 429*, 85 FERC ¶ 61,100 at 61,366 (1998), *reh'g granted, Opinion No. 429-A,* 89 FERC ¶ 61,138 (1999), *reh'g denied, Opinion No. 429-B*, 95 FERC ¶ 61,084 (2001); *accord Ky. Utils. Co., Opinion No. 432*, 85 FERC ¶ 61,274 at 62,105 (1998). In its *Opinion 432*, the FERC did not allow Kentucky Utilities Company ("KU") to change methodologies, stating as follows:

> In conclusion, we believe that either a levelized gross plant or a non-levelized rate design can produce comparable, reasonable results if they are used consistently. Here, however, KU proposes to switch methods. In supporting such a switch, a utility must prove that its proposed method is reasonable in light of its past recovery of capital costs using a different method. Here, KU has not persuaded us that the switch is appropriate in the circumstances of this case.

Regarding CATV attachment charges, considering the historical practice of calculating the charges using the levelized gross plant methodology, the Company maintains that the historical practice should be continued in this current proceeding.

b. The Company is familiar with the clarification of Case No. 2000-00359. The Company does not have information concerning the net plant costs related to the types of poles (35 foot, 40 foot, and 45 foot poles) used to calculate the proposed CATV attachment charge. A rough estimate can be developed by applying the ratio of net plant to gross plant for Account 364 - Poles, Towers, and Fixtures to the applicable gross plant unit costs for 35, 40, and 45 foot poles. As explained above, using net plant necessitates the application of straight line depreciation rather than sinking fund depreciation. Since it has been a historical practice for The Company to use sinking fund depreciation when developing rates, the same method has been used in calculating the proposed rate for CATV attachments.

Table I

(a)	Book Life	35 Years
(b)	Straight Line Depreciation (1/(a))	2.86%
(c)	Sinking-Fund Depreciation (see formula)	0.54%
(d)	Rate of Return	8.32%
(e)	Capital Recovery Factor (CFR) [(c) + (d)]	8.86%

	Non-Levelized Carrying Charges					Levelized Carrying Charges		
Year (1)	Net Investment (2)	Return (3)	Straight Line Depreciation (4)	Non-Levelized Carrying Charges (5)	Present Value at 8.32% ROR (6)	Gross Investment (7)	Non-Levelized Carrying Charges (8)	Present Value at 8.32% ROR (6)
							[(e) x (7)]	
1	$1,000.00	$83.20	$28.57	$111.77	$103.19	$1,000.00	$88.60	$81.80
2	971.43	80.82	28.57	109.39	93.23	1,000.00	88.60	75.51
3	942.86	78.45	28.57	107.02	84.20	1,000.00	88.60	69.71
4	914.29	76.07	28.57	104.64	76.01	1,000.00	88.60	64.36
5	885.71	73.69	28.57	102.26	68.58	1,000.00	88.60	59.42
6	857.14	71.31	28.57	99.89	61.84	1,000.00	88.60	54.85
7	828.57	68.94	28.57	97.51	55.73	1,000.00	88.60	50.64
8	800.00	66.56	28.57	95.13	50.19	1,000.00	88.60	46.75
9	771.43	64.18	28.57	92.75	45.18	1,000.00	88.60	43.16
10	742.86	61.81	28.57	90.38	40.64	1,000.00	88.60	39.84
11	714.29	59.43	28.57	88.00	36.53	1,000.00	88.60	36.78
12	685.71	57.05	28.57	85.62	32.82	1,000.00	88.60	33.96
13	657.14	54.67	28.57	83.25	29.45	1,000.00	88.60	31.35
14	628.57	52.30	28.57	80.87	26.42	1,000.00	88.60	28.94
15	600.00	49.92	28.57	78.49	23.67	1,000.00	88.60	26.72
16	571.43	47.54	28.57	76.11	21.19	1,000.00	88.60	24.67
17	542.86	45.17	28.57	73.74	18.95	1,000.00	88.60	22.77
18	514.29	42.79	28.57	71.36	16.93	1,000.00	88.60	21.02
19	485.71	40.41	28.57	68.98	15.11	1,000.00	88.60	19.41
20	457.14	38.03	28.57	66.61	13.47	1,000.00	88.60	17.92
21	428.57	35.66	28.57	64.23	11.99	1,000.00	88.60	16.54
22	400.00	33.28	28.57	61.85	10.66	1,000.00	88.60	15.27
23	371.43	30.90	28.57	59.47	9.46	1,000.00	88.60	14.10
24	342.86	28.53	28.57	57.10	8.39	1,000.00	88.60	13.01
25	314.29	26.15	28.57	54.72	7.42	1,000.00	88.60	12.02
26	285.71	23.77	28.57	52.34	6.55	1,000.00	88.60	11.09
27	257.14	21.39	28.57	49.97	5.77	1,000.00	88.60	10.24
28	228.57	19.02	28.57	47.59	5.08	1,000.00	88.60	9.45
29	200.00	16.64	28.57	45.21	4.45	1,000.00	88.60	8.73
30	171.43	14.26	28.57	42.83	3.90	1,000.00	88.60	8.06
31	142.86	11.89	28.57	40.46	3.40	1,000.00	88.60	7.44
32	114.29	9.51	28.57	38.08	2.95	1,000.00	88.60	6.87
33	85.71	7.13	28.57	35.70	2.55	1,000.00	88.60	6.34
34	57.14	4.75	28.57	33.33	2.20	1,000.00	88.60	5.85
35	28.57	2.38	28.57	30.95	1.89	1,000.00	88.60	5.40
Sum of Present Value Carrying Charges					$1,000.00			$1,000.00

Table II

(a)	Book Life	35 Years
(b)	Straight Line Depreciation (1/(a))	2.86%
(c)	Sinking-Fund Depreciation (see formula)	0.54%
(d)	Rate of Return	8.32%
(e)	Capital Recovery Factor (CFR) [(c) + (d)]	8.86%

	Non-Levelized Carrying Charges					*Misapplied* Levelized Carrying Charges		
Year (1)	Net Investment (2)	Return (3)	Straight Line Depreciation (4)	Non-Levelized Carrying Charges (5)	Present Value at 8.32% ROR (6)	Net Investment (7)	Non-Levelized Carrying Charges (8)	Present Value at 8.32% ROR (6)
							[(e) x (7)]	
1	$1,000.00	$83.20	$28.57	$111.77	$103.19	$1,000.00	$88.60	$81.80
2	971.43	80.82	28.57	109.39	93.23	971.43	86.07	73.36
3	942.86	78.45	28.57	107.02	84.20	942.86	83.54	65.73
4	914.29	76.07	28.57	104.64	76.01	914.29	81.01	58.84
5	885.71	73.69	28.57	102.26	68.58	885.71	78.48	52.63
6	857.14	71.31	28.57	99.89	61.84	857.14	75.95	47.02
7	828.57	68.94	28.57	97.51	55.73	828.57	73.41	41.96
8	800.00	66.56	28.57	95.13	50.19	800.00	70.88	37.40
9	771.43	64.18	28.57	92.75	45.18	771.43	68.35	33.29
10	742.86	61.81	28.57	90.38	40.64	742.86	65.82	29.60
11	714.29	59.43	28.57	88.00	36.53	714.29	63.29	26.27
12	685.71	57.05	28.57	85.62	32.82	685.71	60.76	23.29
13	657.14	54.67	28.57	83.25	29.45	657.14	58.22	20.60
14	628.57	52.30	28.57	80.87	26.42	628.57	55.69	18.19
15	600.00	49.92	28.57	78.49	23.67	600.00	53.16	16.03
16	571.43	47.54	28.57	76.11	21.19	571.43	50.63	14.10
17	542.86	45.17	28.57	73.74	18.95	542.86	48.10	12.36
18	514.29	42.79	28.57	71.36	16.93	514.29	45.57	10.81
19	485.71	40.41	28.57	68.98	15.11	485.71	43.04	9.43
20	457.14	38.03	28.57	66.61	13.47	457.14	40.50	8.19
21	428.57	35.66	28.57	64.23	11.99	428.57	37.97	7.09
22	400.00	33.28	28.57	61.85	10.66	400.00	35.44	6.11
23	371.43	30.90	28.57	59.47	9.46	371.43	32.91	5.24
24	342.86	28.53	28.57	57.10	8.39	342.86	30.38	4.46
25	314.29	26.15	28.57	54.72	7.42	314.29	27.85	3.78
26	285.71	23.77	28.57	52.34	6.55	285.71	25.32	3.17
27	257.14	21.39	28.57	49.97	5.77	257.14	22.78	2.63
28	228.57	19.02	28.57	47.59	5.08	228.57	20.25	2.16
29	200.00	16.64	28.57	45.21	4.45	200.00	17.72	1.75
30	171.43	14.26	28.57	42.83	3.90	171.43	15.19	1.38
31	142.86	11.89	28.57	40.46	3.40	142.86	12.66	1.06
32	114.29	9.51	28.57	38.08	2.95	114.29	10.13	0.78
33	85.71	7.13	28.57	35.70	2.55	85.71	7.59	0.54
34	57.14	4.75	28.57	33.33	2.20	57.14	5.06	0.33
35	28.57	2.38	28.57	30.95	1.89	28.57	2.53	0.15
Sum of Present Value Carrying Charges					$1,000.00			$721.54