COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

THE APPLICATION OF LOUISVILLE GAS AND ELECTRIC COMPANY FOR CERTIFICATES OF PUBLIC CONVENIENCE AND NECESSITY AND APPROVAL OF ITS 2016 COMPLIANCE PLAN FOR RECOVERY BY ENVIRONMENTAL SURCHARGE	**))))))**	**CASE NO. 2016-00027**

LOUISVILLE GAS AND ELECTRIC COMPANY

RESPONSE TO THE
COMMISSION STAFF'S INITIAL REQUEST

DATED MARCH 11, 2016

FILED: MARCH 24, 2016

VERIFICATION

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

The undersigned, **Robert M. Conroy**, being duly sworn, deposes and says that he is Vice President, State Regulation and Rates, 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.

Robert M. Conroy

Robert M. Conroy

Subscribed and sworn to before me, a Notary Public in and before said County and State, this 24th day of March 2016.

Judy Schooler (SEAL)
Notary Public

My Commission Expires:
JUDY SCHOOLER
Notary Public, State at Large, KY
My commission expires July 11, 2018
Notary ID # 512743

VERIFICATION

COMMONWEALTH OF KENTUCKY)
) SS:
COUNTY OF JEFFERSON)

The undersigned, **Christopher M. Garrett**, 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.

Christopher M. Garrett

Christopher M. Garrett

Subscribed and sworn to before me, a Notary Public in and before said County and State, this 24th day of March 2016.

Judy Schooler (SEAL)
Notary Public

My Commission Expires:
JUDY SCHOOLER
Notary Public, State at Large, KY
My commission expires July 11, 2018
Notary ID # 512743

VERIFICATION

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

The undersigned, **Derek A. Rahn**, being duly sworn, deposes and says that he is Manager - Revenue Requirement 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.

Derek A. Rahn

Subscribed and sworn to before me, a Notary Public in and before said County and State, this 24th day of March 2016.

(SEAL)
Notary Public

My Commission Expires:
JUDY SCHOOLER
Notary Public, State at Large, KY
My commission expires July 11, 2018
Notary ID # 512743

VERIFICATION

COMMONWEALTH OF KENTUCKY)
) SS:
COUNTY OF JEFFERSON)

The undersigned, **Gary H. Revlett**, being duly sworn, deposes and says that he is Director – Environmental Affairs 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.

Gary H. Revlett

Gary H. Revlett

Subscribed and sworn to before me, a Notary Public in and before said County and State, this 24th day of March 2016.

Judy Schooler (SEAL)
Notary Public

My Commission Expires:
JUDY SCHOOLER
Notary Public, State at Large, KY
My commission expires July 11, 2018
Notary ID # 512743

VERIFICATION

COMMONWEALTH OF KENTUCKY)
) SS:
COUNTY OF JEFFERSON)

The undersigned, **Charles R. Schram**, being duly sworn, deposes and says that he is Director – Energy Planning, Analysis and Forecasting 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.

Charles R. Schram

Charles R. Schram

Subscribed and sworn to before me, a Notary Public in and before said County and State, this 24th day of March 2016.

Judy Schooler (SEAL)
Notary Public

My Commission Expires:
JUDY SCHOOLER
Notary Public, State at Large, KY
My commission expires July 11, 2018
Notary ID # 512743

VERIFICATION

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

The undersigned, **John J. Spanos**, being duly sworn, deposes and says that he is a Senior Vice President, of Gannett Fleming Valuation and Rate Consultants, LLC, 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 State, this 16th day of March 2016.

_______________ (SEAL)
Notary Public

My Commission Expires:
February 20, 2019

COMMONWEALTH OF PENNSYLVANIA
NOTARIAL SEAL
Cheryl Ann Rutter, Notary Public
East Pennsboro Twp., Cumberland County
My Commission Expires Feb. 20, 2019
MEMBER, PENNSYLVANIA ASSOCIATION OF NOTARIES

VERIFICATION

COMMONWEALTH OF KENTUCKY)
) SS:
COUNTY OF JEFFERSON)

The undersigned, **R. Scott Straight**, being duly sworn, deposes and says that he is the Director of Project Engineering for Louisville Gas and Electric Company and Kentucky Utilities Company and an employee of LG&E and KU Services Company, 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.

R. Scott Straight

Subscribed and sworn to before me, a Notary Public in and before said County and State, this 24th day of March 2016.

(SEAL)
Notary Public

My Commission Expires:
JUDY SCHOOLER
Notary Public, State at Large, KY
My commission expires July 11, 2018
Notary ID # 512743

VERIFICATION

COMMONWEALTH OF KENTUCKY)
) SS:
COUNTY OF JEFFERSON)

The undersigned, **John N. Voyles, Jr.**, being duly sworn, deposes and says that he is the Vice President, Transmission and Generation Services for Louisville Gas and Electric Company and Kentucky Utilities Company and an employee of LG&E and KU Services Company, 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 N. Voyles, Jr.

John N. Voyles, Jr.

Subscribed and sworn to before me, a Notary Public in and before said County and State, this 24th day of March 2016.

Judy Schooler (SEAL)
Notary Public

My Commission Expires:

JUDY SCHOOLER
Notary Public, State at Large, KY
My commission expires July 11, 2018
Notary ID # 512743

LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Commission Staff's Initial Request Dated March 11, 2016

Case No. 2016-00027

Question No. 1

Witness: Robert M. Conroy

Q-1. Refer to the Direct Testimony of Robert M. Conroy ("Conroy Testimony"), page 7, lines 21–22, which state that the total projected capital cost for Project 29 is $196.9 million, and that LG&E seeks to recover $193.7 million through the environmental surcharge. Explain what costs will be recovered and what costs are not recovered.

A-1. In LG&E's most recent base rate case (Case No. 2014-00372), LG&E included capital costs for environmental projects not yet included in an approved ECR plan in its revenue requirement calculation. The $193.7 million referenced above does not represent any particular component or specific cost associated with the referenced ECR project, but rather represents the total projected capital investment for the project less the amount projected in the test year ending June 30, 2016. To avoid any form of double recovery, capital expenditures will not flow through the ECR mechanism until the amount in base rates is exceeded.

LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Commission Staff's Initial Request Dated March 11, 2016

Case No. 2016-00027

Question No. 2

Witness: Robert M. Conroy

Q-2. Refer to the Conroy Testimony, page 7, line 23, and page 8, lines 1 and 2, which state that the total projected capital cost for Project 30 is $114.1 million, and that LG&E seeks to recover $110.4 million through the environmental surcharge. Explain what costs will be recovered and what costs are not recovered.

A-2. The $110.4 million referenced above does not represent any particular component or specific cost associated with the referenced ECR project, but rather represents the total projected capital investment for the project less the amount projected in the test year ending June 30, 2016. See the response to Question No. 1.

LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Commission Staff's Initial Request Dated March 11, 2016

Case No. 2016-00027

Question No. 3

Witness: Robert M. Conroy

Q-3. Refer to the Conroy Testimony, page 8, lines 8 and 9. Explain LG&E's decision to not seek recovery of operating and maintenance ("O&M") costs for Projects 29 and 30 through the environmental surcharge. If there are O&M costs associated with these projects, explain the kinds of costs, and provide the annual O&M costs not being recovered.

A-3. Any costs related to groundwater monitoring once the projects are complete are expected to be minimal and will be charged to the accumulated depreciation reserve similarly to other closure costs. Future O&M costs, such as mowing, are not currently known, but are expected to be minimal, and will be recovered through future rate case proceedings where applicable.

LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Commission Staff's Initial Request Dated March 11, 2016

Case No. 2016-00027

Question No. 4

Witness: Robert M. Conroy

Q-4. Refer to the Conroy Testimony, page 12, line 21, which states that LG&E is requesting continuation of the 10.00 percent return on equity ("ROE"). Provide the debt and capital structure of LG&E with the weighted cost of capital using 10.00 percent ROE as of December 31, 2015.

A-4. See attached.

LOUISVILLE GAS AND ELECTRIC COMPANY

Adjusted Electric Rate of Return on Common Equity - ECR Plans
As of December 31, 2015

		Per Books 12-31-15 (1)	Capital Structure (2)	Electric Rate Base Percentage (3)	Electric Capitalization (Col 1 x Col 3) (4)	Adjustments to Capitalization (Col 18) (5)	Adjusted Electric Capitalization (Col 4 + Col 5) (6)	Adjusted Capital Structure (7)	Annual Cost Rate (8)	Cost of Capital (Col 8 x Col 7) (9)
ELECTRIC										
1.	Short Term Debt	$ 141,969,180	3.80%	82.350%	$ 116,911,620	$ (33,572,026)	$ 83,339,594	3.80%	0.71%	0.03%
2.	Long Term Debt	1,654,729,467	44.28%	82.350%	1,362,669,716	(391,202,463)	971,467,253	44.28%	4.20%	1.86%
3.	Common Equity	1,940,270,497	51.92%	82.350%	1,597,812,754	(458,699,908)	1,139,112,846	51.92%	10.00%	5.19%
4.	Total Capitalization	$ 3,736,969,144	100.000%		$ 3,077,394,090	$ (883,474,397)	$ 2,193,919,693	100.000%		7.08%
5.	Weighted Cost of Capital Grossed up for Income Tax Effect {ROR + (ROR - DR) x [TR / (1 - TR)]}									10.35%

		Electric Capitalization (Col 4) (10)	Capital Structure (11)	Trimble County Inventories (a) (Col 11 x Col 12 Line 4) (12)	Investments in OVEC & Other (Col 11 x Col 13 Line 4) (13)	JDIC (Col 11 x Col 14 Line 4) (14)	Environmental Compliance Rate Base (Col 11 x Col 15 Line 4) (15)	DSM Rate Base (Col 11 x Col 16 Line 4) (16)	Advanced Coal Investment Tax Credit (b) (Col 11 x Col 17 Line 4) (17)	Total Adjustments To Capital (Sum of Col 12 - Col 17) (18)
ELECTRIC										
1.	Short Term Debt	$ 116,911,620	3.80%	$ (250,492)	$ (44,149)	$ 503,673	$ (34,435,463)	$ (152,966)	$ 807,371	$ (33,572,026)
2.	Long Term Debt	1,362,669,716	44.28%	(2,918,893)	(514,454)	5,869,115	(401,263,766)	(1,782,457)	9,407,992	(391,202,463)
3.	Common Equity	1,597,812,754	51.92%	(3,422,514)	(603,218)	6,881,762	(470,497,171)	(2,089,999)	11,031,232	(458,699,908)
4.	Total Capitalization	$ 3,077,394,090	100.000%	$ (6,591,899)	$ (1,161,821)	$ 13,254,550	$ (906,196,400)	$ (4,025,422)	$ 21,246,595	$ (883,474,397)

(a)	Trimble County Inventories	As of December 31, 2015
	Materials and Supplies	$ 10,413,313
	Stores Expense	1,845,858
	Coal	13,806,296
	Limestone	198,505
	Fuel Oil	103,576
	Emission Allowances	46
	Total Trimble County Inventories	$ 26,367,594
	Multiplied by Disallowed Portion	25.00%
	Trimble County Inv. Disallowed	$ 6,591,899

(b) Reflects Investment Tax Credit treatment per Case No. 2007-00179.

LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Commission Staff's Initial Request Dated March 11, 2016

Case No. 2016-00027

Question No. 5

Witness: Robert M. Conroy

Q-5. Refer to the Direct Testimony of John N. Voyles, Jr. ("Voyles Testimony"), page 3, lines 1–11.

a. Confirm that the difference between the total cost of the new projects of $315.9 million, and the amount to be recovered through LG&E's ECR mechanism of $309.1, represents the amounts currently recovered in base rates.

b. Describe the costs that LG&E currently recovers through base rates for Projects 28, 29, and 30 by each project.

A-5. a. Yes, this is correct.

b. There are no costs related to Project 28 currently being recovered through base rates.

For Projects 29, the total capital cost of the project is $196.9 million of which $193.7 million will be included in the ECR. For Project 30, the total capital cost of the project is $114.1 million of which $110.4 million will be included in the ECR. The difference does not represent any particular component or specific cost associated with the referenced ECR project, but rather represents the amount projected in the test year ending June 30, 2016. See the response to Question No. 1.

LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Commission Staff's Initial Request Dated March 11, 2016

Case No. 2016-00027

Question No. 6

Witness: John N. Voyles, Jr. / Gary H. Revlett

Q-6. Refer to the Voyles Testimony, page 8, regarding the groundwater monitoring and assessment evaluations being conducted at active surface impoundments. When is the groundwater monitoring and assessment required to be completed pursuant to the CCR Rule?

A-6. The CCR Rule requires groundwater monitoring and initial testing be completed by October 17, 2017. Statistical evaluation and additional monitoring requirements extend the deadline a maximum of an additional nine months (July 2018).

LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Commission Staff's Initial Request Dated March 11, 2016

Case No. 2016-00027

Question No. 7

Witness: John N. Voyles, Jr.

Q-7. Refer to the Voyles Testimony, page 11, lines 15–18. Identify the past and current CCR management facilities that are referred to in this statement, and explain why these locations are not included in the 2016 Environmental Compliance Plan ("2016 Plan").

A-7. The reference in the testimony, lines 15-18, is describing the difference in this compliance plan compared to previous plans filed by LG&E, particularly noting closure of impoundments must occur whether or not facilities cease operation. Closure of all wet CCR impoundments, excluding those at Cane Run described on page 23 of my direct testimony, are included in this 2016 Plan. The dry landfill at Mill Creek and the proposed dry landfill at Trimble County are the only CCR Management Facilities not included in this 2016 plan as those facilities will remain in operation, compliant with the CCR Rule.

LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Commission Staff's Initial Request Dated March 11, 2016

Case No. 2016-00027

Question No. 8

Witness: John N. Voyles, Jr.

Q-8. Refer to the Voyles Testimony, page 15, lines 8–11. For Projects 29 and 30, identify by impoundment the closure option that LG&E will employ.

A-8. The conceptual closure approach for the impoundments in Project 29 at Mill Creek are described in Exhibit JNV-3, pages 1-3. The conceptual closure approach for the impoundments in Project 30 at Trimble County Creek are described in Exhibit JNV-4, pages 1-2. Note these are not final, for-construction approaches. Consequently, they might change as engineering progresses.

Also note the proposed closure plans are intended to comply with the CCR Rule in a lowest-reasonable-cost manner on a station-by-station basis, not an impoundment-by-impoundment basis. Therefore, for example, LG&E might propose to incur added expense to clean-close an impoundment because beneficially using the CCR materials from that impoundment to help cap and close another impoundment at the same station would produce net benefits relative to capping and closing both impoundments using other fill material.[1]

Project 29 includes the following:

- Main Pond – Cap and Closure, CCR material will remain in place, beneficially used CCR materials will be utilized to grade the surface to provide run-on and run-off control, and a cap system (Flexible Membrane Liner (FML), 18" of clay soil, and 6" of vegetative soil) will be installed per the CCR Rule.
- Dead Storage Pond – Clean Closure, CCR materials will be removed to non-CCR soils, a CCR Rule compliant liner system (FML overtop of 24" of Clay or a Geosyntec Clay Liner (GCL) and fabricform concrete protection) will be installed and the pond will be repurposed as part of a process facility.
- Clearwell Pond – Clean Closure, CCR materials will be removed to non-CCR soils, a CCR Rule compliant liner system (FML overtop of 24" of Clay or GCL and fabricform concrete protection) will be installed and the pond will be repurposed as part of a process facility.
- Emergency Pond – Clean Closure, CCR materials will be removed to non-CCR soils, a CCR Rule compliant liner system (FML overtop of 24" of Clay or GCL and

[1] *See, e.g.,* Voyles Testimony at 15 lines 11-15.

fabricform concrete protection) will be installed and the pond will be repurposed as part of a process facility.

- Construction Runoff Pond – Clean Closure, CCR materials will be removed to non-CCR soil and backfill with non-CCR material to match the existing grade.

Project 30 include the following:

- Bottom Ash Pond - Cap and Closure, CCR materials will remain in place, beneficially used CCR will be utilized to grade the surface to provide run-on and run-off control, and a cap system (FML, 18" of clay soil, and 6" of vegetative soil) will be installed per the CCR Rule.
- Gypsum Storage Pond - Cap and Closure, CCR materials will remain in place, beneficially used CCR will be utilized to grade the surface to provide run-on and run-off control, and a cap system (FML, 18" of clay soil, and 6" of vegetative soil) will be installed per the CCR Rule.

LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Commission Staff's Initial Request Dated March 11, 2016

Case No. 2016-00027

Question No. 9

Witness: John N. Voyles, Jr.

Q-9. Refer to the Voyles Testimony, page 17, regarding LG&E's decision to go forward with the decision to close the impoundments at the Mill Creek and Trimble County Generating Stations. Has LG&E quantified the risk of waiting to begin closure activities and construction of the process water systems until the analyses as required by the CCR Rule are completed? If so, provide a copy of that risk analysis.

A-9. LG&E has not prepared a written quantitative analysis of the risk of delaying surface-impoundment-closure activities or process-water-system construction until after a CCR Rule triggering event occurs because the consequences of such delay clearly would be shutting down generating units, a very costly and serious concern for reliability of the system. To reach this conclusion, LG&E first assessed what process changes would be necessary to close a CCR impoundment and continue operating the generating station. Then LG&E evaluated the time requirements for design engineering, permitting and approval processes, and finally construction compared against the closure timelines specified by failing one of the requirements prescribed by the CCR Rule that would trigger closure. If LG&E waited for the analyses (Groundwater studies and Location Restrictions (triggering events)) to mandate the closure of a CCR facility, there would not be adequate time to construct the new process water systems that are required to allow the surface impoundments to be closed without ceasing CCR production at the site. The process-water systems are required to facilitate the waste water stream changes and construction schedules for closure of the CCR impoundments and continue operating the generation station. If LG&E waited for a triggering event to occur, generation would be placed in jeopardy as the rule requires ponds to stop receiving CCR materials and non-CCR waste streams and requires the start of closure activities six months after the triggering event. In other words, delaying beginning the construction of process-water systems and related surface-impoundment closures until a triggering event occurs could result in some, if not all, of LG&E's coal units being inoperable for months, if not years. Idling that quantity of generating capacity simultaneously - over 2,700 MW of total coal-fired generation - would severely compromise the LG&E's ability to ensure continuous and reliable service to their customers. It is not clear such a large quantity of replacement capacity would be available for purchase in the wholesale power market, or that LG&E could continually import the enormous quantity of energy necessary to supply their customers without creating and experiencing transmission constraints.

In terms of the potential financial impact of such delays, the cost-benefit analyses performed by Mr. Schram in his Exhibits CRS-1 (Trimble County) and CRS-2 (Mill Creek) indicate that the cost of replacement capacity - if it were available - during unit shut-downs forced by untimely actions to comply with the CCR Rule could be well in excess of $100 million more than the cost of constructing process-water facilities to ensure the coal-fired units could continue to operate.

LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Commission Staff's Initial Request Dated March 11, 2016

Case No. 2016-00027

Question No. 10

Witness: John N. Voyles, Jr.

Q-10. Refer to the Voyles Testimony, page 17, lines 16–18. Identify any and all LG&E surface impoundments at all active or inactive stations that the company believes would not require closure under the CCR rule.

A-10. All CCR surface impoundments at LG&E, except those at Cane Run, are governed by the CCR Rule and the Company anticipates they will be required to close. The CCR impoundments at Cane Run have already either been closed or are in the process of being closed as described on page 23 of my direct testimony.

LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Commission Staff's Initial Request Dated March 11, 2016

Case No. 2016-00027

Question No. 11

Witness: R. Scott Straight

Q-11. Refer to the Direct Testimony of R. Scott Straight ("Straight Testimony"), pages 2 and 3, regarding the potential for the re-emission of mercury and the necessity for Project 28.

a. Provide a detailed description of the mercury re-emission phenomenon, including an explanation of the de-oxidization process, and discuss whether this phenomenon occurs at any other LG&E units that are equipped with wet flue-gas desulfurization technology.

b. Describe evidence that LG&E has obtained that mercury re-emissions are occurring presently at the proposed locations for Project 28.

c. If LG&E is not incurring any mercury re-emissions at this time, describe the risks of postponing Project 28 until such re-emissions occur.

d. Describe all other available control technology that LG&E considered to reduce mercury re-emission, and why the proposed technology was selected.

A-11. a. During the coal combustion process, elemental mercury contained in the coal volatizes and becomes entrained in the flue gas stream. Depending on certain factors such as chloride content within the coal and oxidation conversion rates of Selective Catalytic Reduction (SCR) units, a certain percentage of the elemental mercury loses two electrons and oxidizes into its 2+ oxidation state. Oxidized mercury is much more soluble in water than elemental mercury. Ideally, the oxidized mercury is removed from the flue gas stream in the Wet Flue Gas Desulfurization (WFGD) unit wastewater. However, WFGD chemistry can create conditions where oxidized mercury is reduced back into its water-insoluble elemental state and thus re-emitted back into the flue gas stream.

Oxidation-Reduction Potential (ORP) is the measure of the affinity of WFGD slurry constituents to lose electrons (oxidation) or gain electrons (reduction). The higher the ORP, the more likely these reactions take place. At a high ORP, oxidized mercury regains two electrons and is reduced back into its elemental form. Controlling ORP is key in preventing this reaction.

In order to control ORP, each WFGD will receive an organo-sulfide additive injection system. The organo-sulfide technology mitigates mercury re-emission by lowering WFGD ORP to an optimized range. Each WFGD unit will require a specific dose of organo-sulfide dependent on Unit coal, WFGD design, WFGD chemistry, etc. These rates can only be determined through process optimization once the organo-sulfide injection systems are operational. Another function of the organo-sulfide additive is to bind to oxidized mercury in the WFGD slurry and force it into the WFGD solids. The mercury is then removed from the process through the gypsum. This will help reduce the amount of wastewater that will need to be treated.

b. Trimble County Unit 1 tests conducted in 2012 showed evidence of mercury re-emission and the addition of chemical additives effectively reduced the magnitude of the events. The majority of testing showed increased mercury capture within the WFGD and an overall reduction of mercury emissions.

Trimble County Unit 2 emissions testing conducted in 2013 indicates the Powder River Basin coal/bituminous coal blend that is combusted causes a halogen limited environment constrains mercury oxidation and decreases the effectiveness of any systems to capture oxidized or elemental mercury. Subsequent data has demonstrated the combination of powdered activated carbon injection and chemical additives to be effective in the reduction of mercury emissions.

Ghent Unit 3 tests conducted in 2012 show evidence of mercury re-emissions. Ghent Units 1 and 4 likely experience a similar phenomenon because they combust the same coal and have the same vintage, same technology WFGDs; however, the Companies have not specifically tested these units due to their similarities to Ghent Unit 3.

c. In addition to the Companies experiencing mercury re-emissions, the Electric Power Research Institute (EPRI) has published in their update, *Air Toxics Control by Wet FGD: 2015 Technical Update*, EPRI, Palo Alto, CA: 2015.3002006154, the following statement, "ORP in wet FGD systems has been observed to impact mercury re-emissions, mercury phase partitioning between slurry liquor and solids . . . for example, at high ORP values (>300 mV . . .), mercury is typically partitioned primarily in the FGD liquor, making it available to undergo chemical reduction and to be re-emitted."

Based on past testing and current ORP monitoring, all proposed locations for Project 28 periodically operate in ORP ranges above 300 mV and are therefore susceptible to re-emissions events. By postponing Project 28, LG&E runs the risk of re-emission events and reduced operating flexibility, which would jeopardize cost-effectiveness.

d. LG&E conducted several tests on mercury control additives from different vendors on Mill Creek Units 1, 2, and 3; and Trimble County Units 1 and 2. The testing took place from the second quarter of 2012 through the first quarter of 2016. The WFGD additives that were tested were an inorganic sulfide, organo-sulfide, ferrous sulfide, and PAC. Another technology that was tested was a "front-end" sorbent injected into the boiler and a "back-end" sorbent that could be injected similarly to PAC prior to the Pulse Jet

Fabric Filter inlet or into the WFGD. These two sorbents could only be used as a packaged product. According to the data, the organo-sulfide, two sorbent technology, and PAC showed consistent success in reducing mercury emissions. The organo-sulfide was chosen as the most economical technology to mitigate mercury re-emission.

LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Commission Staff's Initial Request Dated March 11, 2016

Case No. 2016-00027

Question No. 12

Witness: R. Scott Straight

Q-12. Refer to the Straight Testimony, page 6, regarding the injection of a halogenated chemical additive into the coal feeders on the Mill Creek units to provide a more effective process of reducing mercury emissions. Is the supplemental injection technology similar to the refined coal arrangement at the Mill Creek Generating Station that was approved by the Commission in Case No. 2015-00264?[2] If not, explain the difference between the two processes.

A-12. The refined coal technology and the supplemental injection technology are chemically similar but functionally different. Both the refined coal and the supplemental injection technologies utilize halogenated liquids designed to increase mercury oxidation thus reducing mercury emissions. Oxidized mercury is more easily removed from the flue gas with the pulse jet fabric filter and wet flue gas desulfurization technologies, thus reducing overall mercury emissions. However, the technologies differ in implementation and final goals.

The refined coal facility applies two proprietary chemicals to the coal in very small, incremental amounts as the coal is loaded into the power plant bunkers. The goal for the refined coal arrangement is to produce refined coal as defined in Section 45 of the Internal Revenue Code. The refined coal must provide a reduction, measured in lab scale tests, of nitrogen oxide and mercury.

The supplemental injection technology adds a different halogenated liquid to the coal at the unit feeders in continuous metered flow rates. The goal for the supplemental injection technology is to reduce stack mercury emissions to a level below MATS limits. Therefore, while the refined coal arrangement is intended to provide some cost effective mercury mitigation it cannot be relied on for a MATS compliance strategy. In addition, the installation of the refined coal facilities is dependent on Clean Coal Solutions (the refined coal facility owner) finding a tax equity investor for the facility and the successful negotiation of a final arrangement. Any refined coal arrangement would also terminate when the Section 45 Production tax credit expires or when the facility no longer qualifies for the tax credits, currently projected to be in late 2021. Therefore, the supplemental

[2] Case No. 2015-00264, Application of Louisville Gas and Electric Company and Kentucky Utilities Company Regarding Entrance Into Refined Coal Agreements, for Proposed Accounting and Fuel Adjustment Clause Treatment, and for Declaratory Ruling (Ky. PSC Nov. 24, 2015).

injection technology is required for the timely and continuous long term compliance with MATS regulatory limits.

LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Commission Staff's Initial Request Dated March 11, 2016

Case No. 2016-00027

Question No. 13

Witness: Charles R. Schram

Q-13. Refer to the Direct Testimony of Charles R. Schram ("Schram Testimony"), page 5. Provide the Mill Creek cost-benefit analysis using LG&E's standard 30-year analysis period.

A-13. As discussed in Mr. Schram's testimony and exhibits, much uncertainty exists regarding the costs to comply with the U.S. Environmental Protection Agency's Effluent Limitation Guidelines ("ELG") and Clean Power Plan ("CPP"). The final version of the ELG was published only recently and specifies a compliance deadline of no later than December 2023. The Companies have developed high-level ELG compliance cost estimates but more refined cost estimates will not be available for 12 to 18 months. The future of the CPP is particularly uncertain: on February 9, 2016, the U.S. Supreme Court issued an order staying the CPP pending all appellate review of the CPP, including any review by the Court.

Therefore, the Companies chose to evaluate projects 28 and 29 based on costs incurred and benefits produced through 2021 to simplify the analysis and eliminate the need to speculate about compliance costs related to ELG or any other environmental regulation that may impact coal-fired generation beyond 2021. The analysis shows the proposed projects are lowest-reasonable-cost even if the Mill Creek coal units are retired at the end of 2021, which speaks to the value of the Mill Creek coal units in an operating environment with no costs for carbon emissions.

Table A below compares the results of the analysis presented in Table 5 on page 8 of Exhibit CRS-2 to the results of an analysis of the same alternatives evaluated over a 30-year period. For each alternative in the 30-year analysis, four 368 MW NGCC units are assumed to be commissioned at the Mill Creek station in 2022. As a result, the costs for each alternative beyond 2021 are the same and the differences in the present value of revenue requirements ("PVRR") in the 30-year analysis are the same as the PVRR differences in the short-term analysis. The 30-year analysis assumes no costs for carbon emissions throughout the analysis period. This assumption and all other assumptions that impact costs after 2021 have no bearing on the analysis since these assumptions are the same for all alternatives.

Table A – Mill Creek Analysis Results ($M, 2016 Dollars)

		Short-Term Analysis		30-Year Analysis	
Gas Price	**Alternative**	**PVRR of Costs Incurred from 2016 to 2021**	**Diff from Best**	**PVRR (2016-2045)**	**Diff from Best**
Low	Retire in 2019	5,929	225	21,259	225
	Operate through 2021	5,704	0	21,034	0
Mid	Retire in 2019	6,120	319	23,943	319
	Operate through 2021	5,801	0	23,625	0
High	Retire in 2019	6,389	450	26,164	450
	Operate through 2021	5,939	0	25,715	0

Table B below contains a more detailed breakdown of results from the 30-year analysis. In addition to the alternatives considered in Table A, Table B includes a third alternative that assumes the Mill Creek units operate through the end of the 30-year analysis period ("Continued Operation"). This alternative implicitly assumes the Companies' future analysis of more detailed ELG compliance costs results in a recommendation to comply with ELG at Mill Creek and continue operating the Mill Creek units. In an operating environment with no costs for carbon emissions, this alternative is least-cost in all gas price scenarios. The impact of carbon and other regulations impacting coal-fired generation would have to increase the estimated cost of continuing to operate the Mill Creek coal units by $837 million to $3.7 billion before a decision to retire the Mill Creek units would be considered least-cost.

Table B – Mill Creek Analysis Results ($M, 2016 Dollars)

Gas Price	**Alternative**	**System Production Costs**	**Other Capital and FOM**	**ECR Project Costs**	**Replacement Capacity Costs**	**New NGCC Costs**	**Total**	**Diff from Best**
Low	Retire in 2019	17,522	360	81	527	2,769	21,259	1,062
	Operate through 2021	17,457	581	227	0	2,769	21,034	837
	Continued Operation	17,141	2,309	227	0	520	20,197	0
Mid	Retire in 2019	20,207	360	81	527	2,769	23,943	2,737
	Operate through 2021	20,048	581	227	0	2,769	23,625	2,418
	Continued Operation	18,151	2,309	227	0	520	21,206	0
High	Retire in 2019	22,427	360	81	527	2,769	26,164	4,118
	Operate through 2021	22,138	581	227	0	2,769	25,715	3,668
	Continued Operation	18,990	2,309	227	0	520	22,046	0

In the absence of a more detailed ELG compliance cost estimate, the "Continued Operation" alternative utilized the high-level cost estimate included in Table 6 on page 9 of Exhibit CRS-2 ($263 million; see "2016 Plan with Updated ECR Costs").[3] The Companies do not incur ELG compliance costs in the first two alternatives because the Mill Creek units are assumed to retire in 2022. When more refined ELG compliance cost estimates are available in 12 to 18 months, the Companies will assess these costs in light of the uncertainty that exists with carbon regulations and other regulations that may impact coal-fired generation in the future. Even if that analysis concludes retirement is the least-cost alternative, operating the Mill Creek units through at least 2021 – as demonstrated in Table A – is the least-cost retirement alternative.

See attached. The information requested is confidential and proprietary, and is being provided under seal pursuant to a petition for confidential treatment.

[3] A complete summary of capital and fixed O&M cost assumptions through 2045 is attached to this response along with other work papers.

Attachment Confidential

The entire attachment is Confidential and provided separately under seal.

Please also see the Petition to Deviate.

LOUISVILLE GAS AND ELECTRIC COMPANY

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Question No. 14

Witness: Charles R. Schram

Q-14. Refer to the Schram Testimony, pages 5 and 6.

a. Page 5 indicates that high-level estimates for Clean Power Plan ("CPP") and Effluent Limitation Guidelines ("ELG") compliance costs were included in the 30-year cost-benefit analysis. Provide the nature of the costs and amounts included in the analysis.

b. Page 6 indicates that the 30-year cost-benefit analysis did not included any incremental costs for CPP at Trimble County Unit 1. Explain what is included in incremental costs and why they were excluded from the analysis.

A-14. a. The high-level ELG compliance cost estimate utilized in the Trimble County analysis is $143 million (see Table 6 on page 9 of Exhibit CRS-1). The high-level cost estimate for carbon emissions is zero.

b. The Companies' analysis of the Trimble County projects considered high-level estimates for CPP compliance costs, and determined these cost estimates are likely zero. For the reasons discussed in Exhibit CRS-1, the Trimble County coal units would be the last coal units the Companies would retire in a CPP compliance plan. If the Companies' Brown, Ghent, and Mill Creek coal units were retired and replaced with renewable or new natural gas-fired generation with CO_2 emissions ranging from 0 lb/MWh to approximately 1,000 lb/MWh, the Companies' generating portfolio – even if the Trimble County coal units operated at full capacity – would already comply with any reasonable interpretation of the CPP. Therefore, no additional cost for carbon emissions (above and beyond the cost to retire and replace the coal-fired capacity at Brown, Ghent, and Mill Creek) was included in the analysis of the Trimble County projects.

LOUISVILLE GAS AND ELECTRIC COMPANY

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Question No. 15

Witness: Charles R. Schram

Q-15. Refer to the Schram Testimony, Exhibit CRS-1, regarding the Analysis of 2016 ECR Projects Trimble County Generating Station – Generation Planning & Analysis January 2016. Provide all work papers in Excel spreadsheet format with all cell formulas intact and unprotected and all rows and columns fully accessible for all modeling performed in preparing the analyses set forth in Exhibit CRS-1.

A-15. See attached. The information requested is confidential and proprietary, and is being provided under seal pursuant to a petition for confidential treatment.

Attachment
Confidential

The entire attachment is Confidential and provided separately under seal.

Please also see the Petition to Deviate.

LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Commission Staff's Initial Request Dated March 11, 2016

Case No. 2016-00027

Question No. 16

Witness: Charles R. Schram

Q-16. Refer to the Schram Testimony, Exhibit CRS-2, regarding the Analysis of 2016 ECR Projects Mill Creek Generating Station – Generation Planning & Analysis January 2016. Provide all work papers in Excel spreadsheet format with all cell formulas intact and unprotected and all rows and columns fully accessible for all modeling performed in preparing the analyses set forth in Exhibit CRS-2.

A-16. See the response to Question No. 15.

LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Commission Staff's Initial Request Dated March 11, 2016

Case No. 2016-00027

Question No. 17

Witness: John J. Spanos / John N. Voyles, Jr.

Q-17. Refer to the Direct Testimony of John J. Spanos, page 3, lines 5–9., which state that future removal costs of $143,515,000 were established by engineering studies

a. Provide the engineering studies supporting the $143,515,000 removal costs.

b. Provide a summary of amounts and kinds of the removal costs the Mill Creek and Trimble impoundments.

A-17. a. The engineering studies referenced are Exhibit JNV-3 and Exhibit JNV-4. Also see the attached document provided to me from the Company which summarizes the costs of removal for the impoundments based on engineering studies performed by or for the Company.

b. The document provided to part (a) of this response sets forth the location and type of cost of removal projects for each location including Mill Creek and Trimble County. See attached for the underlying asset values for the impoundment facilities provided by the Company.

KU and LG&E 2016 ECR Plan (01/06/2016)

ECR Project	Plant	Facility	Total ($M)	2015	2016	2017	2018	2019	2020	2021	2022	2023
KU 39	Green River	CCR - Main Ash Pond Capping	$20.2	$0.5	$1.1	$8.0	$10.6	$0	$0	$0	$0	$0
KU 39	Green River	CCR - ATB #2 Capping	$21.4	$0.6	$1.1	$8.9	$10.9	$0	$0	$0	$0	$0
KU 39	Green River	CCR - SO2 Pond	$15.2	$0.2	$0.7	$5.2	$9.1	$0	$0	$0	$0	$0
KU 39	Pineville	CCR - Ash Pond Capping	$8.0	$0	$0.3	$0.2	$2.7	$4.8	$0	$0	$0	$0
KU 39	Tyrone	CCR - Ash Pond Capping	$13.1	$0	$0.9	$0.4	$7.3	$4.5	$0	$0	$0	$0
KU 40	Ghent	CCR - ATB #1 Capping	$69.5	$1.0	$3.3	$4.0	$1.3	$6.2	$5.4	$25.9	$22.3	$0
KU 40	Ghent	CCR - ATB #2 Capping	$92.9	$0	$6.7	$10.3	$9.8	$7.0	$21.5	$26.5	$11.1	$0
KU 40	Ghent	CCR - Gypsum Stack	$78.7	$0	$8.3	$20.7	$16.2	$23.7	$9.9	$0	$0	$0
KU 40	Ghent	CCR - Secondary Pond Cleanout	$3.4	$0	$0.4	$0.3	$0.6	$2.1	$0	$0	$0	$0
KU 40	Ghent	CCR - Reclaim Pond Cleanout	$5.4	$0	$0.5	$0.5	$0.3	$2.8	$0.6	$0.6	$0	$0
KU 41	Trimble County	CCR - Ash Pond Capping (net, KU 48%)	$48.8	$0.8	$0.5	$1.1	$3.3	$3.7	$9.6	$7.4	$11.9	$10.6
KU 41	Trimble County	CCR - Gypsum Pond Capping (net, KU 48%)	$13.9	$0	$0.5	$0.7	$1.4	$7.9	$3.5	$0	$0	$0
KU 42	E.W. Brown	CCR - Aux Pond Capping	$32.7	$0	$0.5	$0.7	$0.5	$3.8	$3.4	$3.6	$9.9	$10.2
LGE 29	Mill Creek	CCR - Ash Pond Capping	$51.0	$1.6	$7.1	$0.5	$0.1	$14.3	$27.4	$0	$0	$0
LGE 29	Mill Creek	CCR - Clearwell Pond Cleanout	$5.4	$0.0	$0.6	$4.7	$0.0	$0.0	$0.0	$0	$0	$0
LGE 29	Mill Creek	CCR - Construction Pond Cleanout	$7.3	$0.0	$0.5	$0.3	$6.5	$0.0	$0.0	$0	$0	$0
LGE 29	Mill Creek	CCR - Dead Storage Pond Cleanout	$6.4	$0.0	$0.7	$5.7	$0.0	$0.0	$0.0	$0	$0	$0
LGE 29	Mill Creek	CCR - Emergency Pond Cleanout	$5.5	$0.0	$0.5	$0.3	$4.7	$0.0	$0.0	$0	$0	$0
LGE 30	Trimble County	CCR - Ash Pond Capping (net, LG&E 52%)	$52.9	$0.9	$0.5	$1.1	$3.6	$4.0	$10.4	$8.0	$12.9	$11.5
LGE 30	Trimble County	CCR - Gypsum Pond Capping (net, LG&E 52%)	$15.0	$0	$0.5	$0.7	$1.5	$8.5	$3.8	$0	$0	$0
Total Spend ($M)			$566.7	$5.6	$35.3	$74.2	$90.5	$93.3	$95.6	$72.0	$68.1	$32.3
KU 2016 ECR Project Spend ($M)			$423.2	$3.1	$24.8	$60.9	$74.1	$66.4	$53.9	$64.0	$55.2	$20.8
LG&E 2016 ECR Project Spend ($M)			$143.5	$2.5	$10.5	$13.3	$16.4	$26.8	$41.6	$8.0	$12.9	$11.5

KU	Green River	$56.8
KU	Pineville	$8.0
KU	Tyrone	$13.1
KU	Ghent	$249.9
KU	Trimble County (net)	$62.7
KU	Brown	$32.7
Total ($M)		$423.2

LG&E	Mill Creek	$75.6
LG&E	Trimble County (net)	$67.9
Total ($M)		$143.5

Kentucky Utilities Company
Ponds Proposed for ECR Filing
as of November 2015

	Location	Plant Acct	Year	Cost	Asset ID	Depr Database Loc #
Ghent Ash Pond - ATB#1 Capping	Ghent Unit 1	131200	1974	$1,777,792.39	13678073	5651
Ghent Ash Treatment Basin #2	Ghent Unit 4	131200	1994	16,544,368.66	93594118	5654
	Ghent Unit 4	131200	2004	16,148,295.19	10771518	5654
Ghent Gypsum Stack	Ghent Unit 2 FGD	131200	1994	1,901,133.18	17147798	5658
Ghent Ash Pond - Secondary Pond	Ghent Unit 1	131100	1987	322,828.55	13677771	5651
Ghent Environmemtal Ponds - Reclaim Pond	Ghennt Unit 1 FGD	131100	1997	39,480.55	10632228	5650
Green River Ash Treatment Basin #1 Green River Ash Treatment Basin #2 Green River SO2 Pond	Green River Unit 3	131200	1978	1,831,840.98	10632821	5613
BR Auxiliary Pond - Aux Pond	Brown Unit 1	131200	1995	13,208,176.67	93594073	5621
	Brown Unit 3	131200	2008	19,802,080.26	70577100	5623
Pineville Ash Treatment Basin	Pineville Unit 3	131200	1977	91,265.89	10633623	5643
(Jointly Owned - See LG&E assets below)						
TC Ash Pond-KU - Ash Pond	Trimble County Unit 2	131100	1990	4,562,600.30	31167995	0321
TC Environmental Ponds-KU - Gypsum Pond	Trimble County Unit 2	131200	2011	4,610,665.23	103399148	0321
Tyrone Ash Treatment Basin	Tyrone Unit 3	131200	1977	575,455.72	93594028	5603
Total KU				$81,415,983.57		

Louisville Gas & Electric Company
Ponds Proposed for ECR Filing
as of November 2015

	Location	Plant Acct	Year	Cost		
Mill Creek Ash Pond	Mill Creek Unit 1	131100	1972	$411,750.29	10093145	0211
Mill Creek Clearwell Pond Mill Creek Construction Runoff Pond Mill Creek Dead Storage Pond Mill Creek Emergency Pond	Mill Creek Unit 3	131100	1980	1,263,768.52	10092880	0231
(Jointly Owned - See KU assets above)						
TC Ash Pond -LGE - Ash Pond	Trimble County Unit 1	131100	1990	4,942,817.00	14024169	0321
TC Environmental Ponds -LGE- Gypsum Pond	Trimble County Unit 2	131200	2011	5,057,242.50	103405851	0321
Total LG&E				$11,675,578.31		
Total				$93,091,561.88		

LOUISVILLE GAS AND ELECTRIC COMPANY

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Question No. 18

Witness: Derek A. Rahn

Q-18. Refer to the Direct Testimony of Derek A. Rahn. Provide Exhibit DAR-5 in Excel spreadsheet format with all cells and formula unprotected and fully accessible.

A-18. See attachment being provided in Excel format.

Attachment in Excel

The attachment(s) provided in separate file(s) in Excel format.

LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Commission Staff's Initial Request Dated March 11, 2016

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Question No. 19

Witness: Christopher M. Garrett

Q-19. Refer to the Direct Testimony of Christopher M Garrett ("Garrett Testimony"), page 7, lines 18–23. Describe the capital expenditures for surface-impoundment-related construction projects that are currently included in base rates.

A-19. See the responses to Question No. 1 and Question No. 5b.

LOUISVILLE GAS AND ELECTRIC COMPANY

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Question No. 20

Witness: Christopher M. Garrett / R. Scott Straight

Q-20. Refer to the Garrett Testimony, page 10, lines 11–14. Provide the annual costs of the organo-sulfide and halogenated liquid chemicals.

A-20. The projected annual costs of the organo-sulfide and halogenated liquid chemicals for Trimble County 1 are approximately $1 million.

The projected annual costs of the powdered activated carbon at the Mill Creek station are $4-6 million. Based on test results at Trimble County 1, the annual costs of the organo-sulfide and halogenated chemicals would be $2-3 million.

The cost for these additives are projected to be offset by the savings from the reduction in powdered activated carbon costs approved in the 2011 ECR Plan Projects 26 and 27.

LOUISVILLE GAS AND ELECTRIC COMPANY

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Question No. 21

Witness: Christopher M. Garrett

Q-21. Refer to the Garrett Testimony, page 11, lines 1–5. Explain why the exact amount of the existing facilities to be removed cannot be determined with reasonable accuracy until construction is complete.

A-21. Until final design is complete, LG&E will not know the full scope of assets to be removed and retired. Engineers will continue to evaluate all systems to identify the changes and modifications needed for the closure of the impoundments and the construction of the new process water systems through final completion. The processes used by the Company to identify these facilities in the past were successful and will be used with these facilities.