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PUBLIC SERVICE COMMISSION

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Jeff DeRouen
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Kentucky Public Service Commission
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October 19, 2009

RE: ***THE JOINT APPLICATION OF KENTUCKY UTILITIES COMPANY AND LOUISVILLE GAS AND ELECTRIC COMPANY FOR APPROVAL OF DEPRECIATION RATES FOR TRIMBLE COUNTY UNIT 2 – Case No. 2009-00329***

Dear Mr. DeRouen:

Enclosed please find an original and seven (7) copies of the Response of Kentucky Utilities Company and Louisville Gas and Electric Company to the First Data Request of Kentucky Industrial Utility Customers, Inc. dated October 8, 2009, in the above-referenced proceeding.

Please contact me if you have any questions concerning this filing.

Sincerely,

Robert M. Conroy

Enclosure

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

THE JOINT APPLICATION OF KENTUCKY UTILITIES COMPANY AND LOUISVILLE GAS AND ELECTRIC COMPANY FOR APPROVAL OF DEPRECIATION RATES FOR TRIMBLE COUNTY UNIT 2	)	**CASE NO. 2009-00329**

RESPONSE OF
KENTUCKY UTILITIES COMPANY
AND
LOUISVILLE GAS AND ELECTRIC COMPANY
TO
FIRST DATA REQUEST OF
KENTUCKY INDUSTRIAL UTILITY CUSTOMERS, INC.
DATED OCTOBER 8, 2009

FILED: October 19, 2009

VERIFICATION

COMMONWEALTH OF PENNSYLVANIA)
) SS:
COUNTY OF CUMBERLAND)

The undersigned, **John J. Spanos**, being duly sworn, deposes and says that he is the 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 9th day of October, 2009.

_______________(SEAL)
Notary Public

My Commission Expires:

February 20, 2011

COMMONWEALTH OF PENNSYLVANIA
Notarial Seal
Cheryl Ann Rutter, Notary Public
East Pennsboro Twp., Cumberland County
My Commission Expires Feb. 20, 2011
Member, Pennsylvania Association of Notaries

<u>OBJECTION</u>

Counsel for Kentucky Utilities Company And Louisville Gas And Electric Company objects to the "First Data Request of Kentucky Industrial Utility Customers, Inc" on the grounds that said requests are untimely based on the existing procedural schedule and are not supplemental requests for information. Without waiver of this objection, the response to each request for information of the First Data Request of Kentucky Industrial Utility Customers, Inc is as follows:

KENTUCKY UTILITIES COMPANY
LOUISVILLE GAS AND ELECTRIC COMPANY

Response to First Data Request of
Kentucky Industrial Utility Customers, Inc.
Dated October 8, 2009

Case No. 2009-00329

Question No. 1.1

Witness: John J. Spanos

Q-1.1. Please provide all workpapers developed by and a copy of all source documents relied on by Gannet Fleming in the derivation of the proposed Trimble County 2 ("TC2") depreciation rates by plant account, including, but not limited to the following:

a) Life span.
b) Survivor curve
c) Interim net salvage rate
d) Terminal net salvage rate
e) Depreciation rate

A-1.1. The development of the depreciation rates were determined based on an understanding of the type of facility TC2 would be once constructed. The life span, interim survivor curve and net salvage percent for many facilities were considered, but the TC1 parameters were emphasized for the initial recommended rate for TC2. Once the parameters are established the depreciation rate is calculated. The parameters for TC2 as set forth in the letter from Gannett Fleming (included in the Application for this Case) are listed below:

a-e)

Account	Life Span	Survivor Curve	Interim Net Salvage	Terminal Net Salvage	Depr. Rate
311	55	100-S1.5	(10)	0	2.10
312	55	60-R1.5	(30)	0	4.28
314	55	50-S1.5	(10)	0	2.78
315	55	50-S2	(5)	0	2.49
316	55	40-S2	(5)	0	3.00

All source documents relied on by Gannet Fleming were provided in Case Nos. 2007-00564, Application of Louisville Gas & Electric Company to File Depreciation Study, and 2007-00565, Application of Kentucky Utilities Company to File Depreciation Study. The attached CDs contain the Application and responses to Data Requests as filed in Case Nos. 2007-00564 and 2007-00565.

KENTUCKY UTILITIES COMPANY
LOUISVILLE GAS AND ELECTRIC COMPANY

Response to First Data Request of
Kentucky Industrial Utility Customers, Inc.
Dated October 8, 2009

Case No. 2009-00329

Question No. 1.2

Witness: John J. Spanos

Q-1.2. Refer to the letter from Mr. Spanos of Gannet Fleming attached to the Companies' Application in this proceeding wherein Mr. Spanos provides the proposed depreciation rates and states that "[e]ach of these parameters are established with the general understanding of the new facility and the estimates of other comparable facilities across the United States."

a. Please provide all source documents relied on by Mr. Spanos for his general understanding of the new facility and describe how each source and type of data was used by Mr. Spanos to develop the proposed depreciation rates.

b. Please provide all estimates of other comparable facilities across the United States relied on by Mr. Spanos and describe how each source and type of data was used by Mr. Spanos to develop the proposed depreciation rates.

A-1.2. a. Please see the attached document which contains project information for TC2. The project information sets forth the general understanding Mr. Spanos has related to TC2.

b. Please see the attached sheets, which set forth estimates of other comparable facilities across the United States relied upon by Mr. Spanos. All general information or other related units owned by other electric utilities are not easily organized.

Response to Question 1.2. a.
Project Information for TC2
Witness: John J. Spanos

Project Information Memorandum

I. Summary and Introduction

- *Description of the Project*

Kentucky Utilities Company ("KU") and Louisville Gas and Electric Company ("LG&E") (referred to herein as "the Companies") will construct an Advanced Coal-based Generation Technology project Trimble County Unit 2 ("TC2"). The unit is a nominal 750 net MW super-critical pulverized coal ("SCPC") facility with the latest coal combustion technology, as well as the latest technological advances in efficiency and environmental controls. This new facility will be located at Trimble County Station in Bedford, Kentucky, along the Ohio River, the site of Trimble County Unit 1 ("TC1"), a 511 MW coal-fired facility. TC2 will be a joint project between the Companies, which will own 75% of the project, and the Indiana Municipal Power Agency ("IMPA") and the Illinois Municipal Electric Agency ("IMEA"), which will jointly own 25% of the project, and will serve the needs of the native load customers of these entities. This project is a new electric generating unit with construction to be completed and unit commercialization to take place in year 2010. The nameplate generating capacity is a nominal 750 net MW.

The estimated total cost of the project is approximately $1.1 billion. The estimated amount of qualified investment in eligible property is approximately $876 million. The amount of qualifying advanced coal project credit requested for the project is $125 million.

The following table summarizes the essential requirements for qualification for tax credit, as well as the associated values proving the qualification of this project. The balance of this document explains this qualification in detail.

Summary of Qualifying Criteria Requirements

Table 1

Criteria	Requirement	Trimble County Unit 2
Heat Rate	8530 Btu/kWh	8350 Btu/kWh
SO_2 percent removal	99%	99%
NO_x emissions	0.07 lbs/MMBtu	0.04 lbs/MMBtu (guaranteed) 0.05 lbs/MMBtu (permitted)
PM emissions	0.015 lbs/MMBtu	0.015 lbs/MMBtu
Hg percent removal	90%	90%
Project to power	New electric generation OR Retrofit/repower existing	New electric generation
Amount of project is electrical power	At least 50%	100%
Fuel	At least 75% coal	100% coal
Project location	At one site	Yes; Trimble County Station, 487 Corn Creek Rd, Bedford, KY 40006
Nameplate	At least 400 MW	Nominal 750 net MW
Project Status	Ongoing engineering activities	Approved by State agencies with permits and contracts in place. Refer to Project Milestone Schedule in Appendix A
Project Type	IGCC or qualifying advanced coal project	Qualifying advanced coal project

The new TC2 unit will be powered by an SCPC boiler and steam turbine generator that utilize the latest technological advances in efficiency and environmental controls. The Companies place a high value on efficiency and environmental stewardship, selecting SCPC over a lower cost, less efficient sub-critical pulverized coal facility or a less efficient circulating fluidized bed plant. Moreover, steam cycle conditions were reviewed and raised to the highest conditions for which commercial guarantees were available and reliable operation could be expected with the 5.5 lbs SO_2/MMBtu performance fuel.

TC2 will clearly satisfy the requirements of Section 48A of the Internal Revenue Code in terms of the required design net heat rate. The Guaranteed Design Net Heat Rate provided by Bechtel in the EPC Agreement is 8662 Btu/kWh. When that heat rate is corrected for the fuel heat content and respective atmospheric conditions, as required by Section 48A(f)(2), TC2 has a calculated Design Net Heat Rate of 8350 Btu/kWh, as seen in Table 1. This is further described in the Heat Rate portion of Section II of this Application.

TC2 will easily satisfy the environmental performance requirements of Section 48A, as well. TC2 will be the most environmentally friendly coal-fired unit in Kentucky with lower permit limits for sulfur dioxide ("SO_2") and nitrogen oxide ("NO_x") emissions than any other existing or currently planned coal unit in Kentucky. TC2 will be designed to achieve emission levels which are beyond Best Available Control Technology ("BACT") in several areas, using state-of-the-art emission control technologies. First, in terms of mercury removal, TC2 will be guaranteed to achieve 90% Mercury removal, matching the Section 48A Mercury removal design requirement. The 90% Mercury removal guaranteed for TC2 is necessary to provide a reasonable operating margin to meet the Mercury emission limit of 13×10^{-6} Lb/MWh contained in the project's Air Permit. The Environmental Protection Agency's Clean Air Mercury Rule would provide a limit of more than 21×10^{-6} Lb/MWh. The Mercury limit will be met by a selective catalytic reduction system ("SCR"), a dry electrostatic precipitator ("DESP"), an activated carbon injection system, a pulse jet fabric filter ("PJFF"), a wet flue gas desulfurization system ("WFGD") and a wet electrostatic precipitator ("WESP").

With other adjustments being made to TC1, SO_2 and NO_x emissions from both TC1 and TC2 will not exceed currently permitted limits for the Trimble County Station site, even after the addition of the TC2. Nevertheless, while TC2 was able to net out of the Prevention of Significant Deterioration regulations for SO_2 and NO_x and thus BACT does not apply, it will still be designed to meet 0.05 Lb/MMBtu NO_x which is over 28% better than the Section 48A requirement of 0.07 Lb/MMBtu and have a 99% SO_2 removal rate guarantee which equals the Section 48A requirement for SO_2 removal efficiency.

Finally TC2 will be designed to limit filterable and condensable particulate matter ("PM") emissions to 0.015 lbs/MMBtu. This will be accomplished by installing a DESP, a PJFF and a WESP.

The heat rate and emission limits quoted above as design values are vendor guarantees with liquidated damages or make right requirements contained in executed purchase orders. Hitachi American Limited ("HAL") will supply the steam turbine generator. Wheelabrator Air Pollution Control, Inc. ("WAPC") will supply the air quality control system and Mitsui Babcock Energy Ltd. ("MBEL") will supply the boiler. Bechtel Power Corporation ("Bechtel"), the engineering, procurement and construction ("EPC") contractor for TC2, will design and construct TC2 and provide the ultimate guarantee of TC2 emissions and performance to the Companies.

- *Financing and Ownership Structure*

The TC2 project will be owned by KU (60.75%) and LG&E (14.25%), with the remaining 25% to be owned by IMEA and IMPA. Both KU and LG&E are operating subsidiaries of E.ON U.S. LLC ("E.ON U.S."). KU and LG&E together account for the majority of the revenues of E.ON U.S. E.ON U.S. is ultimately owned by E.ON AG ("E.ON"), an integrated power and gas company based in Dusseldorf, Germany, with 2005 revenues of nearly $67 billion and 2005 net income of $8.8 billion. E.ON's primary areas of operation include central and eastern Europe, the United Kingdom, Scandinavia, and the U.S.

The financing of the TC2 project will include a variety of funding sources, as explained below in greater detail. The Agencies will fund their pro-rata share of costs as incurred and have already issued bonds to fund these respective shares. KU and LG&E will fund the project with a combination of internal cash flow, equity contributions from E.ON U.S., tax-exempt bonds, and intercompany financing from E.ON AG affiliates.

- *Describe the main parties to the project, including background, ownership and related experience*

LG&E is a wholly-owned subsidiary of E.ON U.S. LG&E was incorporated in 1913 in Kentucky. LG&E is a regulated public utility company that supplies natural gas to approximately 324,000 customers and electricity to approximately 396,000 customers in Louisville and adjacent areas in Kentucky. LG&E owns and operates power plants with a generating capacity of 3,514 MW.

KU is a wholly owned subsidiary of E.ON U.S. KU was incorporated in 1912 in Kentucky and 1991 in Virginia. KU is a regulated public utility company that provides electricity to approximately 496,000 customers in over 600 communities and adjacent suburban and rural areas in 77 counties in Kentucky and approximately 30,000 customers in 5 counties in Virginia. In Virginia, KU operates under the name Old Dominion Power Company. KU owns and operates power plants with a generating capacity of 4,570 MW.

LG&E and KU are each subsidiaries of E.ON U.S. Effective December 1, 2005, LG&E Energy LLC was renamed E.ON U.S. Previously, effective December 30, 2003, LG&E Energy LLC had become the successor, by assignment and subsequent merger, to all the assets and liabilities of LG&E Energy Corp. E.ON U.S. is a subsidiary of E.ON, a German corporation. E.ON acquired LG&E Energy through its July 1, 2002 acquisition of Powergen plc, now Powergen Limited ("Powergen"), a United Kingdom company and holding company for E.ON U.K. plc, E.ON's United Kingdom market unit operating parent. LG&E and KU are now indirect subsidiaries of E.ON. As a result of these acquisitions and otherwise, E.ON and E.ON U.S. are registered as holding companies under PUHCA 2005 and were formerly registered holding companies under PUHCA 1935.

LG&E and KU have a long history of successfully building and operating power plants and constructing air quality control equipment. In 1937, LG&E installed one of the first electrostatic precipitators for particulate matter control and, in 1973, was the first utility in the nation to install scrubbers on its power plant units to reduce sulfur dioxide emissions. LG&E partnered with the Department of Energy in the early 1970's on an experimental scrubber project. LG&E and KU have recently installed SCR equipment and WFGD equipment on most of their coal-fired units to further reduce NO_x and SO_2 emissions. The operation of the new equipment has performed better than specifications and ranks in the top tier of utilities in the United States.

IMPA is a not-for-profit corporation and a political subdivision of the State of Indiana. IMPA was created in 1980 for the purpose of jointly financing, developing, owning and operating electric generation and transmission facilities appropriate to the present and projected energy needs of its participating members. IMPA sells power to its members under long-term power sales contracts. IMPA's owned and member-dedicated generating capacity is 811 megawatts.

IMEA is a not-for-profit, municipal corporation and unit of local government of the State of Illinois. IMEA was created in 1984 for the purpose to jointly plan, finance, own and operate facilities for the generation and transmission of electric power to provide for the current and projected energy needs of the purchasing members. IMEA has forty members, each of which is a municipal corporation in the State of Illinois and owns and operates a municipal electric distribution system.

- *Current Project Status and Schedule to Beginning of Construction*

The project continues to progress according to the Project Milestone Schedule. Purchase orders were issued to HAL for the turbine and WAPC for the air quality control system in April 2006. A purchase order was issued to MBEL for the boiler in May 2006. These purchase orders have a total value of more than $300 million. Bechtel has commenced the detailed engineering for the project with their sub-suppliers and placed orders for critical pipe. Site mobilization is scheduled for July 5, 2006.

The overall Summary Schedule of TC2 Project is shown on page 23 of Mr. John Voyles' testimony as Exhibit JNV-5 in the TC2 CCN and can be seen in Appendix B. Construction of TC2 will be primarily performed through a single EPC contract that will primarily include the boiler, air pollution equipment, and turbine generating systems. The Companies expect actual construction to take approximately four years. The current milestone summary is shown in Appendix A.

II. Technology and Technical Information

- *Provide a description of the proposed technology, including sufficient supporting information (such as process flow diagrams, equipment descriptions, information on each major process unit and the total plant, compositions of major streams, and the technical plan for achieving the goals proposed for the project) as would be needed to allow DOE to confirm that the technical requirements of § 48A could, in principle, be met.*

A) Primary Equipment and Systems

TC2 utilizes the latest combustion technologies, demonstrating that combustion technologies will continue to play a vital role in meeting the needs of electric consumers. TC2's primary equipment and systems are described below.

1) Boiler / Steam Turbine

The boiler proposed for TC2 will be a supercritical boiler burning pulverized coal ("PC") with main steam properties of 3690 psia and 1075°F. Supercritical boilers operate above the critical pressure of water (i.e. pressure at which the density of steam and water are the same). By operating at increased steam pressures and temperatures, greater cycle efficiencies and lower emissions are achieved.

The boiler is designed to burn a range of fuels. The boiler will burn a maximum of 6,942 MMBtu/hr or approximately 348 tons of the performance fuel per hour. The performance fuel is comprised of a blend of high sulfur eastern bituminous coal (70%) and low sulfur western sub-bituminous coal (30%) with a 5.5 lbs/MMBtu SO_2 weighted average and 9970 lbs/MMBtu heat content. Startup and stabilization fuel will be Number 2 fuel oil.

The Guaranteed Heat Balance is provided schematically in Appendix C on Diagram Guarantee Heat Balance 310SC38-341.

The boiler is an opposed wall-firing design, designed to maximize efficiency and minimize emissions. For example, low NO_x burners and advanced combustion controls will be used in the boiler to reduce emissions by minimizing NO_x formation in the boiler. Good combustion practices will be utilized to control volatile organic compounds ("VOC") and carbon monoxide ("CO") formation.

The steam turbine is an extraction condensing reheat type using approximately 3690 psia, 1075°F/1075°F throttle steam and eight stages of steam extraction for feedwater heating. The steam turbine is a four casing design: high pressure ("HP"), intermediate pressure ("IP") and two low pressure ("LP") sections. See boiler design drawings in Appendix D.

2) Steam Cycle

The boiler is estimated to generate 5.15 million pounds of steam per hour. Feedwater will flow through the economizer and into the furnace waterwall tubes where it is converted to steam. The steam will continue through the waterwall furnace tubes and enter the primary and secondary superheater sections where it will reach its final pressure and temperature of 3690 psia and 1075°F, respectively. After exiting the secondary superheater section of the boiler, the steam will enter the HP steam turbine via the main steam piping. The steam then passes through the HP casing of the steam turbine.

After exiting the HP turbine casing, the steam returns to the boiler via the cold reheat piping to the reheater sections. After the steam is reheated to 1075°F it enters the IP stage of the steam turbine via the hot reheat piping. The steam then flows into the LP section of the turbine via the crossover piping.

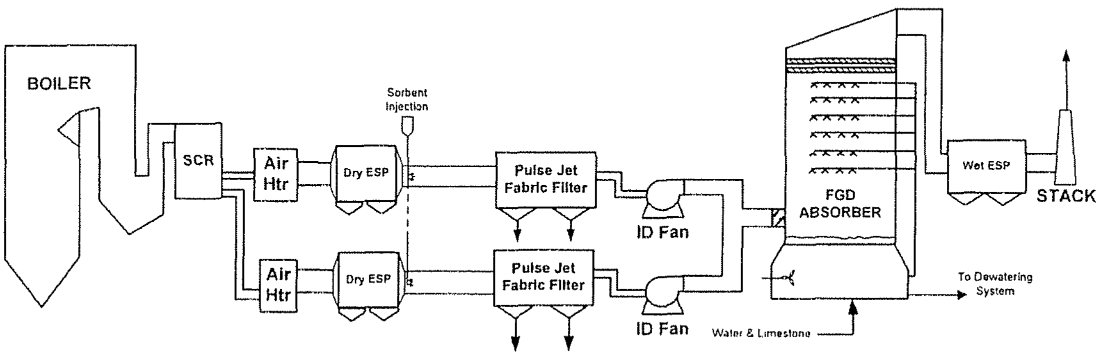
Following the turbine, the steam flows through a number of heat exchangers to transfer heat from the steam to the feedwater until it is finally condensed and returned to the system as feedwater.

Process and Instrumentation Diagrams ("PID") for the steam cycle (Steam Cycle PID 1-6) are in Appendix E.

3) Boiler Flue Gas Path

The coal enters the coal pulverizers as small chunks and exits as a fine powder after the large rollers crush it into small dust-sized particles. The particles are then transported by air (supplied by the primary air fans), and blown into the furnace at the burners, and mixed with secondary air for combustion in the boiler furnace. After the combustion process, the resultant exhaust gases, or flue gas, travel upwards through the boiler furnace, heating the water/steam fluid inside the furnace walls. The flue gas then passes through a superheater section and then enters the convection or backpass section of the boiler where it passes through the reheater sections, further superheaters, and the economizer sections of the boiler. The flue gas then passes through the first piece of equipment in a series of air quality control equipment, the SCR system. From the SCR the flue gas passes through the air pre-heater and then to the remaining Air Quality Control System ("AQCS") components.

The general sequence of equipment that the flue gas will flow through from the boiler to the stack (chimney) is shown below and on the AQCS mass balance diagrams in Appendix F.



4) Air Quality Control Key Equipment

The proposed AQCS for TC2 consists of an SCR, a DESP, a sorbent injection system for mercury ("PAC"), a sorbent injection system for corrosion reduction [$Ca(OH)_2$], a Pulse Jet Fabric Filter ("PJFF"), a Limestone Forced Oxidation WFGD, and a WESP.

The arrangement, dimensions and scope of the equipment are furnished in the AQCS General Arrangement drawings provided in Appendix G.

Flue gas from the air preheater outlet nozzles enters the AQCS and is directed to the DESP inlet nozzles by the ductwork. The flue gas exits the DESP, where the PAC and $Ca(OH)_2$ systems inject dry sorbent into the flue gas stream for mercury and some SO_3 removal. The flue gas enters the inlet plenum of the PJFF for additional particulate removal. Exiting the PJFF, the flue gas travels through axial fans and enters the WFGD. From the WFGD the flue gas travels through the WESP for acid mist removal and out through the existing stack.

a) Selective Catalytic Reduction System

The SCR is BACT for NO_x. The SCR is situated between the economizer outlet and the air pre-heater inlet. The SCR reactions convert NO_x and a reagent, ammonia (NH_3), to water ("H_2O") and nitrogen (N_2). The NH_3 is injected and mixed via a stationary mixing device in the ductwork leading to the SCR. The thorough mixing and even distribution of NH_3 keeps the NH_3 slip below 2 ppm at 3 percent O_2 for the new SCR unit.

The ammonia and NO_x flow through two layers of plate catalyst. The SCR is designed and guaranteed to initially operate with two layers of catalyst; space is designed in the SCR for the addition of a third catalyst layer. The layers of catalyst speed up the ammonia / NO_x reaction and facilitate the creation of H_2O and N_2 as reaction by-products. The catalyst chosen for the project is to convert less that 1 percent of the SO_2 in the flue gas to SO_3 while ensuring the mercury in the flue gas is greater than 55 percent oxidized.

To minimize fly ash collection on the catalyst and the resultant pressure drop, the flue gas will pass through the catalyst sections in a downward flow direction to utilize gravity to assist in the fly ash passing completely through the catalyst sections. Sonic horns will be installed to periodically remove the fly ash from the catalyst.

The TC2 SCR unit will operate with anhydrous ammonia. The existing anhydrous ammonia system for the TC1 SCR at the station will be expanded to support TC2. An inlet loading less than 0.4 Lb/MMBtu of NO_x is anticipated for the SCR while burning the performance fuel. The outlet concentration of NO_x is guaranteed to be less than 0.04 Lb/MMBtu.

b) Dry Electrostatic Precipitator

The DESP is installed down stream of the air pre-heater to remove marketable fly ash (particulate matter) prior to the injection of PAC or $Ca(OH)_2$. The DESP is guaranteed to remove 90% of the particulate matter in the flue gas stream which reduces the particulate matter loading and wear on the PJFF.

The DESP uses electrical current to charge particles contained in the flue gas by passing them over discharge electrodes. The charged particles are then placed in an electrostatic field that drives them to collection plates (or curtains). After an increment of build-up, the collection surface plates are rapped to knock the particles into a hopper below.

The horizontal inlet nozzles of the DESP contain perforated plates to ensure uniform gas flow at the inlet face of the precipitator. The horizontal outlet nozzles contain vertical channel baffles for uniform gas distribution.

The DESP is a three field design consisting of pairs of collecting electrode curtains spaced sixteen inches apart. Suspended within each pair of curtains is a rigid discharge electrode assembly. The curtains are made of roll formed 18 gauge sheet steel and are 50 feet in height by nearly 12 feet in width.

Both the discharge electrodes and the collecting curtains are rapped by shaft-driven tumbling hammer assemblies to remove the particulate matter. The particulate matter "sheets" off the curtains and electrodes falling into the hoppers below the DESP. The particulate matter is removed from the hoppers for sale or disposal.

c) Sorbent Injection Systems for Mercury Control Powdered Activated Carbon ("PAC")

Mercury ("Hg") enters the system in three forms; oxidized, elemental, and particulate. Oxidized and particulate mercury are abated throughout the air pollution control system as a co-benefit of the proposed technologies. Particulate mercury is readily removed in the baghouse, WFGD process, and WESP process. Elemental mercury can be converted to oxidized mercury across some of the equipment, allowing for its abatement in the air pollution control processes.

Elemental mercury can oxidize in the boiler due to combustion reactions. It is also oxidized across the SCR due to catalytic reactions. The oxidized mercury can react with unburned carbon ("LOI"), removing a fraction of it in the air preheater and the baghouse. The oxidized mercury is water soluble, leading to further abatement in the wet FGD. Further abatement of mercury takes place in the WESP, where all three forms of mercury can be collected.

An activated carbon injection system ("PAC") will be installed to ensure that TC2 meets the mercury permit limits. The PAC will be injected between the DESP and the PJFF. PAC is BACT for mercury removal. The PAC system is guaranteed to remove 90% of the total mercury and to meet the Air Permit emission limits of 13×10^{-6} Lb/MWH. The Mercury emission guarantee is contingent upon a maximum fuel Mercury content of 15.2×10^{-6} Lb/MmBtu (uncontrolled), flue gas temperatures at the air heater outlet no greater than 350 °F, and total mercury oxidation levels at least 55% for flue gas temperatures greater than 340 °F but less than or equal to 350 °F or at least 20% for flue gas temperatures at or below 340 °F.

d) Hydrated Lime [$Ca(OH)_2$]

Due to the range of fuels and operating parameters specified, there are conditions in which condensation of SO_3 may occur in the PJFF. To mitigate the corrosion and operational issues related to sulfuric acid mist in the PJFF, a $Ca(OH)_2$ system has been installed. The sorbent will be directly injected in the flue gas stream upstream of the baghouse to chemically react with SO_3 and H_2SO_4 to produce filterable compounds. These compounds or particulates are efficiently collected in a baghouse. Pipes or lances used to carry the sorbent will form a grid perpendicular to the flow of the flue gas inside the duct work. The sorbent exits the pipes or lances and enters the flue gas through an atomizing spray designed to promote mixing.

e) Pulse Jet Fabric Filter

From the DESP, the flue gas will be routed into a PJFF for particulate removal. PJFF is BACT for filterable particulate matter.

TC2 will be supplied with one PJFF system comprised of two fields each containing six compartments. Each compartment contains 1,140 bags for a total of 13,680 bags in the PJFF. Flue gas with boiler fly ash, PAC and $Ca(OH)_2$ enters an inlet plenum and is distributed to each of the individual compartments. Flue gas enters the compartments and is evenly distributed via a baffle to the filter bag socks. The particle laden flue gas flows through the sides of the filters (where the particles collect and form a filter cake on the outside of the bags) and clean flue gas exits the top of the filter. In order to clean the filters, a pulse of air is directed into the top of the filters, causing a pressure change and dislodging the cake from the filter so that it falls into the collection hopper for disposal. Each filter bag is supported on a wire cage; the bags and cages are independently suspended from a tubesheet at the top of each compartment.

There are numerous filter bag material alternatives for a baghouse. However, due to the high sulfur content of the coal to be burned, a degradation resistant fabric filter material has been selected for this particular application.

The baghouse is designed for a filterable PM emission rate of 0.015 Lb/MMBtu.

f) Wet Flue Gas Desulfurization

The flue gas exits the fabric filter baghouse and enters into the WFGD process via the ID fans. The wet limestone forced oxidized WFGD system proposed for the TC2 is BACT for removal of sulfur dioxide from the flue gas. The WFGD is designed and guaranteed to remove 99% of the SO_2 in the flue gas without the addition of reaction enhancement chemicals, such as an organic acid. The WFGD is also effective in removing particulate matter, HF and oxidized mercury.

In the WFGD system, the SO_2 undergoes several reactions—absorption, neutralization, regeneration, oxidation, and finally precipitation—with different chemicals until it finally forms a marketable, wallboard-grade gypsum.

The proposed WFGD consists of one absorber tower with two dual flow trays designed to treat 100% of the flue gas generated from the boiler. The absorber contains six limestone slurry spray levels and is designed to achieve 99% SO_2 removal. The flue gas travels vertically up the absorber tower through the dual flow trays (creating contact and mass transfer between the limestone slurry and the SO_2) and counter-current to the spray patterns. The atomized slurry droplets from the spray headers drop onto the dual flow trays and then to the reaction tank below the absorber tower. The slurry in the reaction tank is thoroughly mixed with oxidation air, which is compressed atmospheric air, blown into the reaction tank to precipitate the gypsum.

The WFGD system is designed for 5.5 Lb SO_2/MMBtu loading and 99 percent SO_2 removal efficiency while burning the performance fuel.

After passing through the WFGD the scrubbed gas is fed into a stand-alone WESP.

g) Wet Electrostatic Precipitator

From the WFGD process, the flue gas will enter a horizontal WESP. A WESP is BACT for removal of SO_3 and sulfuric acid mist. The WESP is designed and guaranteed to meet the permitted level of 0.0037 Lb/MMBtu of sulfuric acid at the stack. The WESP is also effective in removing many types of particulates, including acid mist, oil and tar based condensed aerosols, filterable particulates, and oxidized mercury.

The proposed WESP has three fields; two fields are required to meet the project guarantees and a third field is an installed spare. The active treatment area in each field consists of pairs of collecting electrode curtains spaced eleven inches apart. Suspended within each pair of curtains is an array of rigid discharge electrodes. The WESP contains 369 seven-and-a-half feet long by forty foot tall collection curtains and 3,600 forty foot long discharge electrodes.

A WESP charges particles in the flue gas by passing the particles over energized electrodes. The electrostatically charged particles then flow through an electrostatic field that drives them to oppositely charged collecting plates. The collection plates are continuously irrigated by an overhead washing system to eliminate concerns relating to contaminant build-up. The particle saturated water flows down the plates to the bottom of the WESP and to the reaction tank of the wet FGD system.

The WESP is anticipated to have a removal impact on all particulate matter, both filterable and condensable. The guaranteed total particulate matter concentration (filterable and condensable) following the WESP is 0.015 Lb/MMBtu.

From the WESP, the flue gas flows to the stack (chimney) and exits into the atmosphere.

B) Material Handling

1) Coal

Trimble County's existing equipment is sufficient to handle the coal and limestone needs for 2,350 MW of PC capacity. However, the addition of TC2 will require that some modifications to the existing coal handling system be made to manage the new concept of blending fuels at the site.

All coals will be transported to the site by barge; the station can moor between 1 and 30 barges with barge capacities ranging from 900-ton to 1,500-ton. Coal will be transferred from the barges using the existing coal unloading system. The existing coal conveying and crushing systems also meet the demands of both TC1 and TC2.

A coal blending operation is proposed for TC2, to blend low sulfur, western sub-bituminous coal with high sulfur eastern bituminous coal.

2) Limestone

Limestone will be used as the flue gas desulfurization ("FGD") reagent and will be transported to the site by barge, just as it is for TC1. The current reagent handling and slurry preparation systems are of sufficient capacity to support the additional demands of TC2.

3) Water

The station is currently permitted under Kentucky Pollutant Discharge Elimination System ("KPDES") Permit # KY0041971 to use the Ohio River for its water needs. The addition of TC2 will not change this method of operation or the existing KPDES permit. See also Section IX, Permits including Environmental Authorizations.

4) Cooling Towers

TC2 will utilize the existing natural draft cooling tower on the site for its operations.

Heat Rate Requirement

- *Provide evidence sufficient to demonstrate that the proposed technology meets the definition of "Advanced Coal-Based Generation Technology," either as integrated gasification combined cycle (IGCC) technology, or other advanced coal-based electric generation technology meeting the heat rate requirement of 8530 Btu/kWh*
- *The applicant must provide actual heat rate and heat rate corrected to conditions specified in § 48A(f)(2)*
- *For projects including existing units, the applicant must provide information sufficient to justify that the proposed technology meets heat rate requirements specified in § 48A(f)(3)*

The EPC Agreement Guarantees with Bechtel for TC2 (attached as Appendix H) provides a guaranteed heat rate for the performance fuel at 59°F dry bulb and 60% relative humidity ("RH") is 8,662 BTu/kWh. The performance fuel has a heat content of 9970 Btu/Lb. To calculate the "design net heat rate" as defined in Section 48A(f)(2), Bechtel's guaranteed heat rate is adjusted both for site reference conditions and for the heat content of the design coal.

With respect to site reference conditions, the Bechtel guarantee conditions of 59°F and 60% RH (which is the ISO standard for system design) needed to be converted in order to apply the conditions contained in Section 48A(f)(2)(D) of 14.4 psia, 63°F dry bulb, 54°F wet bulb, and 55% RH. Those adjustments were made in Trimble County 2, Ambient Change, Tax Credit

Study (attached as Appendix I). The performance data for the existing cooling tower, which was originally designed for two units but which will be enhanced in conjunction with this project, is based upon 90°F dry bulb conditions. As indicated in Appendix I, the guaranteed performance heat rate was first adjusted to a 90°F condition utilizing the existing cooling tower performance data. That 90°F case was then adjusted to the 54°F wet bulb criteria.

The adjusted heat rate at these conditions is 8751.9 Btu/KWh. This value should be conservative since expected enhancements to the cooling tower, which will further enhance performance, were not factored into the calculation.

Also, the heat rate of 8751.9 Btu/KWh described above was adjusted for fuel heat content of 9970 Btu/Lb pursuant to the formula in Section 48A(f)(2). This calculation shown below results in a Design Net Heat Rate of 8,350.3 Btu/kWh:

$$8{,}751.9 * [1-[(13{,}500-9{,}970)/1000]*.013] = 8{,}350.3 \text{ Btu/kWh}$$

This calculation yields the heat rate provided in Table 1 of this Application.

SO_2 Percent Removal Requirement

- *Provide evidence sufficient to ensure that the proposed project is designed to meet the following performance requirements:*
  SO2 percent removal.........99 percent

The WAPC purchase order provides for WAPC to guarantee 99% SO_2 removal from the TC2 flue gas. The relevant sections of the WAPC Guarantees are attached as Appendix J.

NO_x Emissions Requirement

- *NOx emissions...............0.07 lbs / MMBTU*

The EPC Agreement provides for Bechtel to guarantee that NO_x emissions from TC2 will not exceed 0.04 Lb/MMBtu provided the burner stoichiometry does not exceed 1.0; otherwise the guarantee will be 0.05 Lb/MMBtu. See Appendix H.

PM Emissions Requirement

- *PM emissions................0.015 lbs / MMBTU*

The EPC Agreement provides for Bechtel to guarantee that total (filterable and condensable) PM emissions from TC2 will not exceed 0.015 Lb/MMBtu. See Appendix H.

Mercury Removal Requirement

- *Hg percent removal.........90 percent*

The WAPC purchase order provides for WAPC to guarantee 90% Hg removal from the TC2 flue gas. The relevant sections of the WAPC Guarantees are attached as Appendix J.

Coal Project Requirements

- *Provide evidence sufficient to demonstrate that the project meets the requirements for qualifying advanced coal projects as specified under § 48A(e)(1) including:*

- *The project will power a new electric generation unit or retrofit/repower an existing electric generation unit. At least 50% of the useful output of the project is electrical power.*

TC2 is a new electric generation unit. The Guaranteed Heat Balance is provided schematically in Appendix C on Diagram Guarantee Heat Balance 310SC38-341. It shows that 100% of the useful output is electrical power.

See Appendix K for CCN for evidence that TC2 is a new electric generation unit and that over 50% of the useful output of the project will be electrical power.

- *The fuel for the project is at least 75% coal (as defined in § 48A(c)(4)), on an energy input basis.*

Appendix L contains Fuel Quality specifications to the project EPC contract. It shows that 100% of the fuel for TC2 will be coal.

- *The project is located at one site and has a total nameplate electric power generating capacity of at least 400 MW.*

A Site Plan for the nominal 750 net MW unit is located in Appendix M.

- *Provide information and data, including examples of prior similar projects completed by applicant, EPC contractor, and suppliers of major subsystems or equipment which support the capabilities of the applicant to construct and operate the facility.*

Appendix N contains reference information of the companies involved in the TC2 project.
E.ON U.S.
Bechtel Power Corp.
Mitsui Babcock Energy Limited
Hitachi American Limited
Wheelabrator Air Pollution Control, Inc.

- *Include the project status and relevant information from ongoing engineering activities. Also include in an appendix any engineering report or reports used by the applicant to develop the project and to estimate costs and operating performance.*

As seen in the Project Milestone Schedule located in Appendix A, the project is progressing toward Full Notice to Proceed and site mobilization in July 2006. Key equipment consisting of the boiler, turbine and AQCS has been procured. Detailed engineering is underway. Examples of the detailed engineering and approvals in connection with the project are listed below.

- Burns & McDonnell Report – A preliminary Engineering Study commissioned in 2002 to determine the feasibility, sizing, parameters and project approach strategy of the proposed TC2. The project and the scope have been optimized from this original study to the current status of the Purchase Orders with the Key Equipment sub-suppliers to Bechtel Power (the EPC Contractor). See Appendix O.
- Air Quality Permit, see Appendix P.
- Kentucky State Board Generation and Transmission Siting Order, see Appendix Q.
- Certificate of Public Convenience and Necessity Order ("CCN"), see Appendix K.
- Fuel Specification, see Appendix L.
- Guaranteed Heat Balance, see Appendix C.
- Trimble County 2, Ambient Change, Tax Credit Study, see Appendix I.
- Mass Balances, see Appendix F.
- Preliminary Steam Cycle PID's, see Appendix E.
- Reference, see Appendix N.
- Project Milestone Schedule, see Appendix A.
- Site Plan, see Appendix M.
- AQCS General Arrangements, see Appendix G.
- Participation Agreement (IMEA, IMPA, LG&E, KU), see Appendix R.
- Purchase Orders for Turbine, Boiler and AQCS ("PO"), see Appendix S.

III. Priority for Integrated Gasification Combined Cycle Projects

For IGCC Projects, the applicant must submit information sufficient for categorization and prioritization of projects for certification, including:

- *Identification of the primary feedstock (as defined in section 5.02(5) of Notice 2006-24), and all other feedstocks.*
- *If applicable, evidence demonstrating that the project will be capable of adding components that can capture, separate and permanently sequester greenhouse gases.*
- *A plan showing how project by-products will be marketed and utilized.*
- *Other benefits, if any.*

This section is not applicable as TC2 uses an advanced coal project technology other than IGCC.

IV. Site Control and Ownership

- *Provide evidence that the applicant owns or controls a site in the United States of sufficient size to allow the proposed project to be constructed and operated on a long-term basis.*

LG&E owns the approximately 2,200 acre Trimble County Station Site. At Construction Closing, LG&E transferred an undivided ownership interest in the TC2 site (approximately 6.5 acres under TC2) to the other owners of TC2. Section 6.2 of the Participation Agreement attached as Appendix R describes fully the site ownership. A copy of the Trimble County Station Site deeds is attached as Appendix T.

- *Describe the current infrastructure at the site available to meet the needs of the project.*

As noted in the Project Description in Section II above, TC2 will be installed at an existing site in the E.ON U.S. fleet. This site has existing infrastructure for coal handling, limestone handling, water intakes, cooling tower and civil works complete. See the Site Plan in Appendix M.

- *Provide information supporting applicant's conclusion that the proposed site can fully meet all environmental, coal supply, water supply, transmission interconnect, and public policy requirements.*

All necessary environmental approvals to commence construction of TC2 have been obtained. The Title V, Acid Rain/NO_x Budget permit for the construction/operation of a new electrical generating unit was received/deemed final January 4, 2006. The Kentucky Pollutant Discharge Elimination System ("KPDES") Permit, currently in effect, expires September 30, 2007. The additional anticipated flows will be included during the renewal application in March 2007. The Companies do not anticipated significant changes to the KPDES permit as a result of TC2. In fact, the Companies are in compliance with the certification requirement under Section 48A(e)(2)(A) that all Federal and State environmental authorizations to commence construction have been received.

In terms of other regulatory approvals, on November 1, 2005 the Kentucky Public Service Commission issued an order granting TC2 a CCN and on November 9, 2005 amended that order to include a Site Compatibility Certificate. On January 27, 2004 an Interconnection and Operating Agreement ("I&O") was executed with the Midwest Independent System Operator identifying all necessary electrical infrastructure improvements and assigning almost all construction responsibility to the transmission unit of the Companies. The Companies received a CCN for the direct interconnection part of these facilities on September 8, 2005. An additional CCN for transmission system upgrades was received on May 26, 2006.

Water for TC2 will be taken from the Ohio River through existing intake structures and under existing permits. Coal will be purchased by the Companies' Fuel Department. It is anticipated that coal for the first year of operation will be fully contracted for in 2009. This is consistent with the Companies' practice for its existing 6,000 MW coal fleet.

The CCN order is attached as Appendix K. The Air Quality Permit is attached as Appendix P. The Interconnection and Operating Agreement is attached as Appendix U.

V. Utilization of Project Output

- *A projection of the anticipated costs of electricity and other marketable by-products produced by the plant.*
- *Provide evidence that a majority of the output of the plant is reasonably expected to be acquired or utilized.*
- *Describe any energy sales arrangements that exist or that may be contemplated, e.g., Power Purchase Agreement or Energy Sales Agreement, and summaries of their key terms and conditions.*
- *Include as an appendix any independent Energy Price Market Study that has been done in connection with this project, or if no independent market study has been completed, provide a copy of the applicant-prepared market study.*
- *Identify and describe any firm arrangements to sell non-power output, and provide any evidence of such arrangements. If the project produces a product in addition to power, include as an appendix any related market study of price and volume of sales expected for that product.*

A. Costs of Electricity and Other Marketable By-Products

Table 2 shows the anticipated costs of electricity for TC2 as excerpted from the filed CCN Application for TC2:

Table 2 – Costs of Electricity for TC2

Year	Demand ($/kW-Month)	Energy ($/MWh)	Total Cost ($/MWh)
2010	14.35	14.39	38.96
2011	14.38	14.60	39.23
2012	14.41	14.82	39.50
2013	14.45	15.04	39.78
2014	14.48	15.27	40.07
2015	14.52	15.50	40.35

By-products are currently forecast to be stored on site, however marketing opportunities are continuing to be evaluated. Therefore, long term markets for by-products (flyash, bottom ash, synthetic gypsum) are not known at this time. Additionally, fuel selection and combustion characteristics will determine the final quality of by-products, and therefore their market potential.

The primary fuel will be high sulfur coal, much like TC1, which has marketable by-products. However, TC2 will also have a new coal blending system and will be able to utilize a variety of coals through blending (including high sulfur eastern Kentucky, lower sulfur eastern and western sub-bituminous (Power River Basin) coals).

B. Majority of Output Will Be Used for Native Load

As regulated utilities, the Companies have an obligation to serve all customers located in their service territories and must be prepared to meet load growth in those areas. Therefore, the Companies prepared a 2004 Joint Load Forecast which forecasts the need for base-load capacity beginning in 2010. The Companies' energy requirements are forecast to grow at a compound average rate of 2.0 percent between 2005 and 2020. Moreover, the Companies' annual peak demand is forecast to grow at an average annual rate of 2.0 percent from 2005 to 2020. As shown in the highlighted cells in Table 3, the Companies will need between 401 MW and 552 MW of additional capacity by 2012 in order to serve native load requirements and maintain a reserve margin between 13% and 15%. Table 3 further indicates the combined Companies' capacity shortfalls through 2012, exclusive of the addition of TC2.

The Companies historically have maintained adequate reserves to insure reliable least cost generation supply to native load customers. Reserve margin is necessary because additional generation must be available should there be an unexpected loss of generation, reduced supply due to equipment problems, unanticipated load growth, variance in load due to extreme weather conditions, and/or disruptions in contracted purchased power.

The Companies also conducted a Resource Assessment to compare the options available to meet the projected needs of their respective customers. The purpose of a Resource Assessment is to identify the least-cost option for implementing the overall resource acquisition plan. That assessment determined that the construction of TC2 was the least-cost option to meet those needs. Construction is essential for the Companies to continue to meet their obligation, as regulated utilities, to provide reliable low-cost power to their growing native loads.

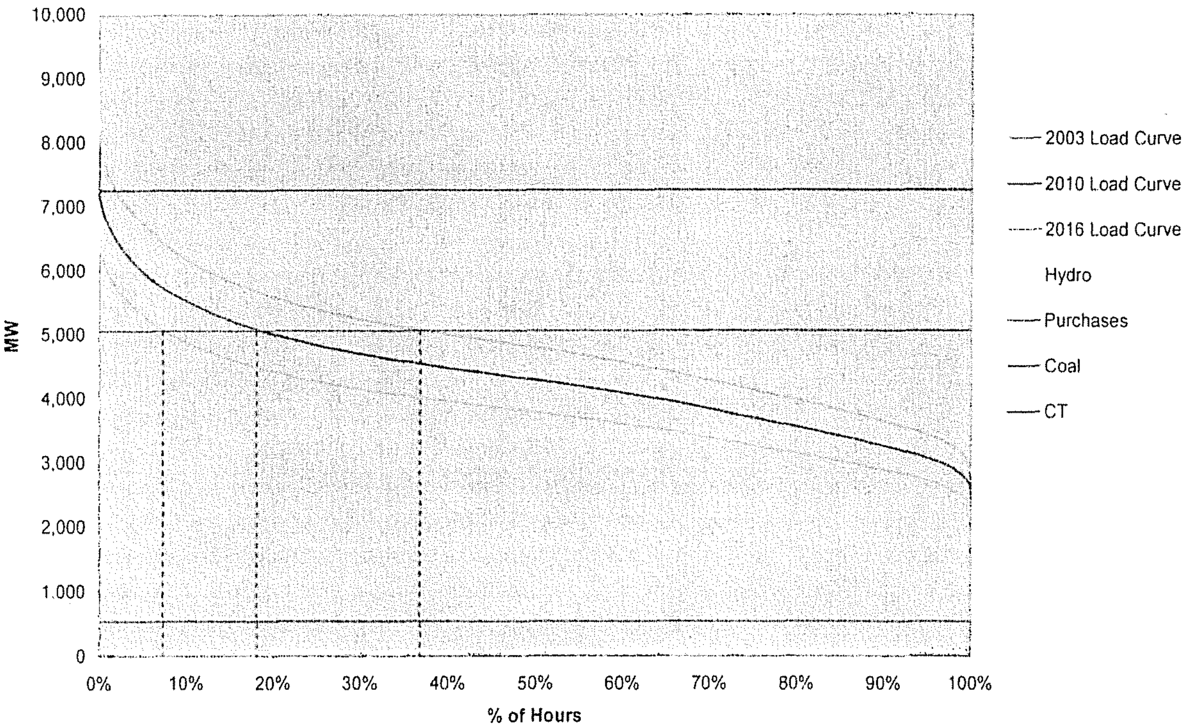
In addition to satisfying reserve margin requirements, the Companies must meet the energy needs of their customers in a least-cost manner. This requires the optimization of the generation portfolio among differing technology and fuel types (i.e., coal, gas, hydro, etc.). The Companies' triennial Integrated Resource Plan ("IRP") identifies when new resources are needed and provides an analysis of the type of new resource that is likely to offer the lowest lifetime system cost. Prior to the TC2 CCN, the most recent IRP filing was in October 2002. The IRP is a complete resource assessment and acquisition plan that considers all utility supply-side and demand-side resource alternatives, including enhancements to existing generation facilities. However, the IRP does not consider the dynamic purchase power market and the opportunities that may exist in the marketplace from time to time. Because the purchase power market is dynamic, the Companies continually review the "buy versus build" decision. The future resource mix is optimized such that the revenue requirements of serving load are minimized.

Table 3 - Capacity Needs for Reserve Margin Range
Revised December 2004
(All values in MW at Summer Peak)

Component		2004	2005	2006	2007	2008	2009	2010	2011	2012
Peak Load		6,632	6,796	6,911	7,051	7,225	7,372	7,483	7,656	7,762
CSR/Interruptible		100	100	100	100	100	100	100	100	100
Existing DSM		44	67	89	108	116	116	116	116	116
2002 IRP DSM Program		0	0	1	1	2	2	2	2	2
Net Load		6,488	6,629	6,722	6,842	7,006	7,153	7,264	7,437	7,543
Existing Capability		7,615	7,608	7,609	7,596	7,582	7,547	7,549	7,550	7,555
Purchases		593	605	574	572	572	571	570	569	568
Total Supply		8,208	8,213	8,183	8,168	8,154	8,118	8,119	8,119	8,123
13 % RM	MW Need Before DSM	-827	-647	-486	-313	-103	100	224	419	535
	MW Need After DSM	-877	-722	-588	-437	-237	-35	90	285	401
15 % RM	MW Need Before DSM	-696	-513	-350	-174	40	245	372	570	688
	MW Need After DSM	-747	-590	-453	-300	-97	109	235	434	552
Existing Reserve Margin, %	Before DSM	25.7%	22.7%	20.1%	17.5%	14.4%	11.6%	10.0%	7.4%	6.0%
	After DSM	26.5%	23.9%	21.7%	19.4%	16.4%	13.5%	11.8%	9.2%	7.7%

By 2010, it will have been 20 and 26 years, respectively, since LG&E and KU constructed a base load unit. From 1990 to 2010, the Companies' energy needs will have grown by 14,500 GWh or 61%. The amount of time which the Companies rely upon resources other than base load resources (owned or purchased) is expected to increase substantially from 2003 to 2016 as shown in the following graph. Based upon an assumed 85% coal unit availability, the native load energy requirement was above the Companies' base load resources 7% of the time for 2003. That figure increases to 18% by 2010 and 36% by 2016. In the graph below, horizontal lines represent cumulative resource capabilities in MW. For example, the Combustion Turbine line is the summation of Hydro, Purchases, Coal and CT capacity. The curves are Load Duration Curves ("LDC") and represent load levels for each hour in the respective years.

Load Duration Curve Comparison with Purchases
85% Availability of Base Load Generation



As part of the Resource Assessment, the Companies issued a Request for Proposals ("RFP") on April 1, 2003 to meet the base load needs of the Companies for 2010 and beyond. The RFP indicated specific requirements such as the amount and timing of capacity and energy needed. The RFP was sent to over 90 potential energy suppliers, with nine responses being received. The nine responses resulted in ten proposals ranging from 10 MW to 500 MW. A screening evaluation was conducted to first assess and rank all viable proposals. The responses to the RFP included Purchase Power Agreements ("PPA") and shared unit ownership, and were evaluated against the Companies self-build option at TC2. Three suppliers were eliminated during the screening process due to their considerably higher costs, and a preliminary detailed analysis was performed based on data used in the screening analysis. Table 4 briefly describes the six offers that were analyzed following the screening analysis.

Table 4 – Six Proposals Analyzed (besides TC2)

Marketer	Description
A	200 MW unit contingent PPA; Term: 6/2007 through 5/2027
B	200 MW in 2007 and increasing to 500 MW in 2009; Thirty year PPA starting in early 2007.
C	500 MW firm (LD) PPA; Term: 1/2007 through 12/2021
D	485 MW asset ownership; Available in early 2005
E	500 MW PPA; Term: 10/2007 through 9/2022
F	114 MW average summer capacity, anticipated 716 GWh annually; Term: Thirty year PPA starting in early 2007

The analysis compares the revenue requirements associated with each option over a thirty-year time period. The analysis is performed primarily using PROSYM, a proprietary production cost model provided by *Global Energy Decisions*. The inputs to the program include generating unit characteristics, load projections, fuel and purchased power cost projections, and other information. The output includes generation, purchased power, and off-system sales profiles, along with the corresponding production costs. This cost information is combined with the capital cost information for each option to determine the net present value of revenue requirements for each resource alternative.

The conclusion of the Resource Assessment is that the construction of TC2 for 2010 in-service is the preferred alternative for meeting native load capacity needs for 2010 and beyond. This is represented as the Case Ranked one in Table 5 below, which shows the lowest Net Present Value of Revenue Requirements ("NPVRR") - utilizing the market conditions at the time of the study for the CCN. A summary of results for the final detailed analysis can be found in Table 5 that follows:

Table 5 – Ranking of Cases Studied in CCN

Case	NPVRR ($000)	Rank	Delta from Min ($000)
TC2 2010 and Marketer F's PPA in 2013	16,370,555	1	0
Marketer F's PPA in 2010 and TC2 2011	16,377,517	2	6,962
TC2 and Marketer F's PPA in 2010	16,399,793	3	29,238
TC2 in 2010	16,443,935	4	73,380
TC2 in 2011	16,450,735	5	80,180
Marketer E's Joint Ownership and Marketer F's PPA in 2010	16,462,347	6	91,792
Marketer E's Joint Ownership in 2010	16,508,339	7	137,784
Marketer E's Joint Ownership in 2011	16,512,364	8	141,809
No Baseload Addition	16,850,301	9	479,746

TC2 will be one of the least-cost providers across the fleet after it is built. As a new base-load unit, and a low-cost provider, TC2 will be expected to operate at full load. Therefore, the PROSYM production cost model forecasts TC2 capacity factors on the order of 90% to 92% for the years that were modeled.

The Companies received approval from the KPSC for the CCN application for Trimble County 2 on November 1, 2005. This document affirms the reasonableness of the unit's expected output and is included in Appendix K.

C. Energy Sales Arrangements

Due to the nature of the Companies' business, (i.e. an obligation to serve all customers located in their service territories), no energy sales arrangements or Power Purchase Agreements have been established. However, IMEA and IMPA do have Participation Agreements ("PA") with the Companies. This specifically details that IMEA and IMPA will own 12.12% and 12.88% respectively, and will share in the construction costs, subject to all applicable approvals.

D. Energy Price Market Study

In lieu of an Energy Price Market Study, the market prices the Companies' Risk Coordination Group approved were used with the TC2 CCN and are provided in Appendix V. The data is given by periods of time, 5x16, 7x8, and 2x16 where 5x16 represents weekday peak hours, 7x8 represents off-peak hours, and 2x16 represents weekend peak hours. The "Into-Cinergy" column shows the pricing for the delivery point near the TC2 site that has since been renamed the "Cinergy Hub." With the unit projected in service in 2010, the market price forecast for that year in particular is shown in Table 6 which is excerpted from the aforementioned appendix. Note: forward market prices only indicate the relative merit position of TC2 in relation to market purchases. Upon commissioning, TC2 will be utilized to serve native load customers and thus not be subject to market price fluctuations for operation.

Table 6 - Market Price Assumptions for TC2

Into-Cinergy	5x16	7x8	2x16
1/1/2010	50.18	30.26	35.63
2/1/2010	48.46	28.48	36.40
3/1/2010	47.29	28.35	34.13
4/1/2010	44.10	29.06	33.16
5/1/2010	41.23	25.20	30.59
6/1/2010	46.03	27.15	33.31
7/1/2010	62.36	32.00	42.98
8/1/2010	61.17	30.26	42.37
9/1/2010	43.40	23.85	31.65
10/1/2010	42.35	28.33	33.14
11/1/2010	42.82	26.67	30.72
12/1/2010	43.17	28.17	37.39

E. Non-Power Output Sales

The new generating unit will provide only electricity and no other usable energy sources; however, as previously mentioned, byproducts from the combustion of coal (bottom ash, flyash) and by-products from environmental control technologies (synthetic gypsum) may be sold should a market develop.

VI. Project Economics

- *Describe the project economics and provide satisfactory evidence of economic feasibility as demonstrated through the financial forecast and the underlying project assumptions.*

Appendix W contains a section of the CCN application filed with the KPSC that contains the least cost analysis proving the economic feasibility of TC2. The CCN application does not contain the effects of the tax credits. Appendix X contains the financial model of TC2 showing the effects of the advanced coal tax credit.

- *Discuss the market potential for the proposed technology beyond the project proposed by the applicant.*

TC2 will be the first facility in the country to employ SCPC technology to burn principally high sulfur eastern coals and achieve the required efficiency under Section 48A. The required net heat design rates will be achieved by utilizing the steam conditions of 3690 psia and 1075° F. Once TC2 proves the viability of long term operations at these conditions, the Companies predict that all future high sulfur coal plants will employ these or higher steam conditions.

TC2 also will be the first new plant to utilize a SCR, DESP, ACI, PJFF, WFGD and WESP arrangement to control Mercury while minimizing solid waste issues. Mercury control remains a challenge for all coal facilities. On its website for the Mercury Emission Control R&D Program, DOE maintains that "technology to cost-effectively reduce mercury emissions from coal-fired power plants is not yet commercially available." The Companies, however, expects that the combination of control technologies will allow for the removal of 90% of mercury emissions in a cost-effective manner. The powered activated carbon employed at TC2 is from Norit-Americas; its trade name is DARCO FGD. DARCO FGD has been tested in numerous Department of Energy/National Energy Technology Laboratory studies. Norit-Americas were part of the research team for the Phase II Mercury Control Project – *Evaluation of Sorbent Injection for Mercury Control.* Once these environmental control features are proven, it is likely that most future PC coal plants in the U.S. burning eastern bituminous coals, will utilize this approach to control mercury emissions.

Section 48A was added to the tax code in recognition of the fact that coal must remain a sustainable fuel source. And, in meeting new emissions control requirements, we cannot afford to abandon our reliance on eastern coal, notwithstanding its high sulfur content. The technologies to be utilized by TC2 represent a giant leap forward in assuring the continued use of high sulfur coal while promoting enhanced efficiencies and reduced air emissions.

- *Show calculation of the amount of tax credit applied for based on allowable cost.*

Total Capital Project Budget (Generation)	$1,056,000,000
Less IMEA/IMPA 25% ownership	(264,000,000)
KU/LG&E eligible generating plant	792,000,000
KU/LG&E eligible transmission plant	84,000,000
Total eligible plant	876,000,000
Tax credit percentage	x 15%
Tax credit calculated	$131,400,000
Tax credit applied for	$125,000,000

Annual capital expenditures above represent financial statement basis projections. Actual tax basis expenditures will reflect differences such as capitalized interest and will be used to determine the qualifying expenditures.

VII. Project Development and Financial Plan

- *Provide the total project budget and major plant costs, e.g., development, operating, capital, construction, and financing costs.*

Steam Generator	$108,800,000
Steam Turbine	47,000,000
Air Quality Control System Package	220,200,000
SCR	24,400,000
Ash Handling	18,400,000
Other Pollution Control Costs	42,000,000
Balance Of Project and Construction	579,700,000
Development Costs	15,500,000
Total Capital Project Budget	$1,056,000,000
Less IMEA/IMPA 25% ownership	(264,000,000)
Total Capital Project Budget-Trans.	84,000,000
Total Capital	$876,000,000

Bechtel is the engineering, procurement and construction contractor for TC2 and will design and construct TC2 and ultimately provide the guarantee of TC2 emissions and performance to the Companies.

- *Describe the overall approach to project development and financing sufficient to demonstrate project viability. Provide a complete explanation of the source and amount of project equity. Provide a complete explanation of the source and amount of project debt. Provide the audited financial statements for the applicant for the most recently ended three fiscal years, and the unaudited quarterly interim financial statements for the current fiscal year.*

- *For internally financed projects, provide evidence that the applicant has sufficient assets to fund the project with its own resources. Identify any internal approvals required to commit such assets. Include in an appendix copies of any board resolution or other approval authorizing the applicant to commit funds and proceed with the project.*

- *For projects financed through debt instruments either unsecured or secured by assets other than the project, provide evidence that the applicant has sufficient creditworthiness to obtain such financing along with a discussion of the status of such instruments. Identify any internal approvals required to commit the applicant to pursue such financing. Include in an appendix, copies of any board resolution or other approval authorizing the applicant to commit to such financing.*

- *For projects financed through investor equity contributions, discuss the source and status of each contribution. Discuss each investor's financial capability to meet its commitments. Include in an appendix, copies of any executed investment agreements.*

- *If financing through a public offering or private placement of either debt or equity is planned for the project, provide the expected debt rating for the issue and an explanation of applicant's justification for the rating. Describe the status of any discussions with prospective investment bankers or other financial advisors.*

- *For projects employing nonrecourse debt financing, provide a complete discussion of the approach to, and status of, such financing.*

KU and LG&E are not "project financing" the construction of TC2. Instead, the plant will be funded as part of the overall capital structure of the Companies. The sources of funds available to fund all projects of the Companies including TC2 will include internally generated cash, equity contributions, tax-exempt bonds, and intercompany loans from E.ON AG affiliates. It is important to note that the amounts identified below will be available to fund the TC2 project as well as all other capital projects of the Companies.

Internally generated cash flow will be a significant source of funds for the project. KU does not anticipate paying dividends during the construction of the project, and will reinvest the funds otherwise paid as dividends to fund capital projects. In 2005, KU generated cash from operations totaling $221 million. LG&E is planning to continue to pay dividends during construction as its funding requirements will be significantly lower. However, LG&E generates significant cash flow to use toward funding the project as demonstrated by its 2005 results when cash from operations totaled $150 million.

KU and LG&E are committed to maintaining strong investment grade credit ratings, and E.ON U.S. will make equity contributions to KU during the term of the project to ensure that KU's capital structure remains balanced. Current forecasts suggest that E.ON U.S. will contribute equity of at least $300 million between 2006 and 2010. E.ON U.S. will obtain funds for these contributions from E.ON AG affiliates in the form of equity or intercompany loans. LG&E anticipates equity contributions totaling $50 million from E.ON U.S. to maintain a balanced capital structure.

Certain costs of the TC2 project qualify for tax-exempt financing which is the lowest cost funding source available to the Companies. The amount of tax-exempt funding available to the applicants is limited by the availability of an annual allocation of the state volume cap. The pool available in Kentucky for private activity issuers such as the Companies is very small with each project currently capped at just below $17 million per application. In recent years, the state has had cap available for a second round of allocation to projects, but even at $34 million annually the pool is somewhat limiting. KU received two allocations in 2005 and once thus far in 2006 for projects unrelated to TC2. KU and/or LG&E will continue to seek tax-exempt allocations to the extent that there are qualifying costs.

The final source of funds will be intercompany loans from affiliates of E.ON AG. E.ON's financing strategy is to borrow all funds externally at the ultimate parent, E.ON AG, and lend funds down to subsidiaries as needed. This strategy is designed to limit structural subordination issues that arise when multiple subsidiaries issue debt externally. The only exceptions to the strategy are situations wherein the subsidiaries can borrow at more attractive rates than E.ON as is true with the tax-exempt bonds discussed above. E.ON makes funds available to the applicants at market based rates using indicative pricing quotes from independent third parties. Loans are expected to be unsecured obligations of the applicants and the timing of the loans will be at the discretion of the applicants. E.ON has approved the TC2 project as evidenced by the attached board resolution in Appendix Y and E. ON is prepared to provide the necessary funding to complete the project.

E.ON is the world's largest investor-owned power and gas company headquartered in Dusseldorf, Germany with a market capitalization at year-end 2005 of €60 billion. E.ON has ready access to the capital markets if required to raise funds externally. E.ON is rated AA- by Standard & Poor's and Aa3 by Moody's and maintains lines of credit for general corporate purposes of €10 billion. E.ON also has recently entered into an additional credit facility totaling €32 billion related to the proposed acquisition of Endesa. At year-end 2005, E.ON had a positive net debt position; i.e. cash exceeded outstanding debt. As further evidence of financial strength, in 2005 E.ON generated cash flow from operations totaling €6.6 billion.

Both of the Agencies sold bonds in June 2006 to finance most of their respective shares of TC2. The proceeds from these bond sales are currently held by a trustee, but are available to the Agencies to pay for the construction of TC2. The Agencies may sell additional bonds in 2009 or later to finish funding construction.

- *In an appendix, provide (1) an Excel based financial model of the project, with formulas, so that review of the model calculations and assumptions may be facilitated; provide pro-forma project financial, economic, capital cost, and operating assumptions, including detail of all project capital costs, development costs, interest during construction, transmission interconnection costs, other operating expenses, and all other costs and expenses, and (2) a report of an independent financial analyst in accordance with the instructions in Section G of this Appendix B.*

Description of Modeling

In order to obtain a CCN for the TC2 project from the Kentucky Public Service Commission, the Utilities had to demonstrate that the project was a component of the least-cost capacity expansion plan for the combined system. The modeling that was performed in the Resource Assessment for the TC2 CCN utilized two different computer models. These are briefly described below:

Overview of the PROSYM Chronological Simulation Model

The PROSYM production costing model was used to evaluate the production cost revenue requirements associated with each of the scenarios. PROSYM is a product of *Global Energy Decisions*. It is a chronological electric utility production simulation modeling system that is designed for performing planning and operational studies on an hourly basis. It uses convergent Monte Carlo analysis to give the least cost and most economical dispatch of generation resources and simulates the Power Supply System Agreement ("PSSA") joint dispatch of both KU and LG&E units. That is, the generating units of both companies are dispatched in economic order to meet the combined demands of both KU and LG&E customers. PROSYM is able to simulate the utilization of typical generation resources and the purchased power alternatives considered in this analysis.

Overview of the Capital Expenditure and Recovery ("CER") Model

The CER module of Strategist (formerly called PROSCREEN II) calculates revenue requirements associated with capital expenditures for both the construction and in-service periods. These capital revenue requirements are combined with the production cost revenue requirements to produce a total system revenue requirement for the study period. The CER contains capital information on resource projects associated with the various cases evaluated in this resource assessment. Inputs to the CER include construction cost profiles, depreciation schedules and various economic assumptions.

Unit Operation Conditions

TC2 was modeled using the following operating conditions:

- Super-critical coal-fired unit
- Summer/winter ratings of 732/750 MW
- Summer/winter Full Load Heat Rate ("HHV") of 9079/8651 Btu/kWh
- Availability: 93%
- Location: Trimble County plant within LG&E transmission system

Proforma Project Financial Projections

Having established – from the perspective of *system* requirements – the optimal timing for the commissioning of the TC2 plant, the proforma project financial projections model (attached Excel file) shows the financial performance of the *stand-alone project* under the following assumptions:

- Project revenue reflects its 'revenue requirements' as reported for regulatory purposes (revenue requirements include depreciation, interest on debt, fair return on equity capital, fixed O&M, and required taxes; all variable costs are treated as 'pass-through' items).
- The project earns its revenue requirements only when the associated costs are included in the rate base (i.e. after a filing for rate adjustment); and the timing of rate filings is determined by the financial position of the Utilities as a whole rather than by the needs of a single project.

- The model thus replicates 'imperfect' rate treatment reflective of a mid-2005 'snapshot' view of the financial outlook for the utilities; in the base case scenario the first rate adjustment – and thus the first opportunity to allow recovery of project costs - occurs in 2010, based on a calculation of prior year ('test year') revenue requirements.
- Project revenues remained essentially fixed between rate cases (although there is allowance for load growth in the interim) irrespective of the profile of actual revenue requirements; this tends to result in 'under-recovery' of costs during the construction phase and 'over-recovery' during the operating phase (*from an individual project perspective*).
- The project maintains the same capital structure as the utilities.

Capital Costs

The expected capital costs for TC2 construction in its entirety is approximately $1.1 billion. The project cost was originally derived with the assistance of Burns & McDonnell Engineering in 2002. The cost was then independently reviewed and updated by Cummins and Barnard in January 2004 to account for subsequent scope and market changes. This includes escalation, contingency, and owner's costs, but excludes costs for transmission facilities. Since 25% of the project is owned by IMEA and IMPA, the total construction costs to the Companies will only be 75% or approximately $800 million, excluding transmission facilities. The Companies' portion of the costs is shown in Table 7 as follows.

Table 7 – TC2 Costs (75% ownership only)
(Nominal $000s)

Year	Capital	Transmission	Total
2005	7,500	0	7,500
2006	76,300	5,200	81,500
2007	206,300	6,300	212,600
2008	304,200	26,900	331,100
2009	166,800	42,100	208,900
2010	30,900	3,800	34,700
Grand Totals	**792,000**	**84,300**	**876,300**

Operations and Maintenance Costs

The projected annual expenses associated with the Companies' 75% ownership of TC2 in 2004 dollars for non-fuel costs is $4 million for variable and $7.3 million for fixed O&M.

VIII. Project Contract Structure

- *Describe the current status of each of the agreements set forth below. Include as an appendix copies of the contracts or summaries of the key provisions of each of the following agreements:*

  - *Power Purchase Agreement (if not fully explained in Section IV)*

Not applicable, since energy will be used to serve native load customers.

  - *Coal Supply: describe the source and price of coal supply for the project. Include as an appendix any studies of coal supply price and amount that have been prepared. Include a summary of the coal supply contract and a copy of the contract.*

TC2 is being designed to burn a variety of different fuels. It is currently anticipated that the main fuel will be a blend of low sulfur sub-bituminous coal from the Powder River Basin ("PRB") and high sulfur bituminous coal from the Illinois and Northern Appalachian Basins. The Companies currently purchase over fifteen million tons of coal per year for its other generating stations and will use the current policy and procedures to purchase the TC2 coals. Agreements for TC2 coals will be secured one or two years prior to commercial operation.

  - *Coal transportation: explain the arrangements for transporting coal, including costs.*

TC2 fuels will be transported on the Ohio River to the site via barge. The station is equipped with a coal barge unloader capable of off-loading the additional requirement of TC2. LG&E currently has a contract with Crounse Corporation to transport all barge coal and anticipates using Crounse to transport TC2 coals.

  - *Operations & Maintenance Agreement: include a summary of the terms and conditions of the contract and a copy of the contract.*

Article 7 of the Participation Agreement ("PA") provides the following:

LG&E and KU shall have the sole obligation and authority to manage, control, maintain and operate TC2. The Companies shall prepare an annual O&M budget and submit it to the Coordination Committee for approval. The Companies shall operate and maintain TC2 using Good Utility Practice.

Service Life and Net Salvage Statistics - Electric

	Client:	Oklahoma Gas and Eclectic		Cincinnati Gas and Electric		Arizona Public Service	
	Study date:						
	Study date:	2002		2003		2002	
	Procedure / Basis:	ASL / Rem. Life		ASL / Rem. Life		ASL / Rem. Life	
FERC Acct.	Description	Survivor Curve	Net Salvage Percent	Survivor Curve	Net Salvage Percent	Survivor Curve	Net Salvage Percent
	STEAM PRODUCTION PLANT						
311	STRUCTURES AND IMPROVEMENTS	100 - R2.5*	(15)	100 - R2.5*	EXPENSED	75 - S1.5*	(20)
	LANDFILL						
312	BOILER PLANT EQUIPMENT	90 - R2*	(10)	55 - S0.5*	EXPENSED	48 - L2*	(20)
	COMBUSTION INITIATIVE						
	UNIT COAL TRAIN						
	POWER OPERATED						
	UNCLASSIFIED						
	SCRUBBERS						
313	ENGINES & GENERATORS						
314	TURBOGENERATOR UNITS	75 - S1.5*	(10)	55 - R1.5*	EXPENSED	65 - R2*	(20)
315	ACCESSORY ELECTRIC EQUIPMENT	60 - R3*	0	55 - R2.5*	EXPENSED	60 - R2,5*	(20)
316	MISCELLANEOUS PLANT EQUIPMENT	30 - S0*	(5)	75 - R1*	EXPENSED	40 - R2*	(20)
	COMBUSTION INITIATIVE						
	AIR MONITORING EQUIPMENT						
	FURNITURE						
	DATA PROCESSING EQUIPMENT						
	CARS						
	TOOLS, SHOP AND GARAGE EQUIPMENT			37 - S0.5*	EXPENSED		
	POWER OPERATED EQUIPMENT						
	COMMUNICATION EQUIPMENT						
	MISCELLANEOUS						

* Curve shown is interim survivor curve.

Service Life and Net Salvage Statistics - Electric

	Client:	AmerenUE		Omaha Public Power District		PSI Energy, Inc.	
	Study date:						
	Study date:	2000		2001		2002	
	Procedure / Basis:	ASL / Whole Life (w/ 20Yr.True-up)		ASL / Rem. Life		ASL / Rem. Life	

FERC Acct.	Description	Survivor Curve	Net Salvage Percent	Survivor Curve	Net Salvage Percent	Survivor Curve	Net Salvage Percent
	STEAM PRODUCTION PLANT						
311	STRUCTURES AND IMPROVEMENTS	120 - S0*	(24) - (60)	100 - R2.5*	(30)	100 - R2.5*	(35)
	LANDFILL						
312	BOILER PLANT EQUIPMENT	60 - S0*	(24) - (60)	65 - S0.5*	(30)	50 - S0.5*	(30)
	COMBUSTION INITIATIVE						
	UNIT COAL TRAIN	22 - R3*	30		25	30 - R3*	(25)
	POWER OPERATED						
	UNCLASSIFIED						
	SCRUBBERS						
313	ENGINES & GENERATORS						
314	TURBOGENERATOR UNITS	100 - S0*	(24) - (60)	60 - R3*	(30)	65 - S1*	(30)
315	ACCESSORY ELECTRIC EQUIPMENT	80 - R2*	(24) - (60)	55 - S1.5*	(30)	55 - R2*	(10)
316	MISCELLANEOUS PLANT EQUIPMENT	70 - L0*	(24) - (60)	50 - S2*	(30)	40 - S0*	(5)
	COMBUSTION INITIATIVE						
	AIR MONITORING EQUIPMENT						
	FURNITURE						
	DATA PROCESSING EQUIPMENT						
	CARS						
	TOOLS, SHOP AND GARAGE EQUIPMENT				(30)		
	POWER OPERATED EQUIPMENT						
	COMMUNICATION EQUIPMENT						
	MISCELLANEOUS						

* Curve shown is interim survivor curve.

Service Life and Net Salvage Statistics - Electric

	Client:	**Idaho Power Company**		**El Paso Electric Company**		**Duke Power Company**
	Study date:					
	Study date:	**2001**		**2002**		**2003**
	Procedure / Basis:	**ASL / Rem. Life**				**ASL / Rem. Life**

FERC Acct.	Description	Survivor Curve	Net Salvage Percent	Survivor Curve	Net Salvage Percent	Survivor Curve	Net Salvage Percent
	STEAM PRODUCTION PLANT						
311	STRUCTURES AND IMPROVEMENTS	90 - S1*	(10)	100 - S1.5*	(5)	100 - S0.5*	(20)
	LANDFILL						
312	BOILER PLANT EQUIPMENT	55 - R3*	(10)	80 - S2*	(5)	45 - S3*	(20)
	COMBUSTION INITIATIVE						
	UNIT COAL TRAIN	25 - R3*	20				
	POWER OPERATED						
	UNCLASSIFIED						
	SCRUBBERS	70 - R1.5*	(10)				
313	ENGINES & GENERATORS			40 - R2.5*	(10)		
314	TURBOGENERATOR UNITS	50 - S0.5*	(10)	75 - R3*	(10)	55 - S2.5*	(20)
315	ACCESSORY ELECTRIC EQUIPMENT	65 - S1.5*	0	65 - S1*	0	50 - S1.5*	(20)
316	MISCELLANEOUS PLANT EQUIPMENT	45 - R0.5*	0	55 - R2*	0	60 - R1.5*	(20)
	COMBUSTION INITIATIVE						
	AIR MONITORING EQUIPMENT						
	FURNITURE						
	DATA PROCESSING EQUIPMENT						
	CARS						
	TOOLS, SHOP AND GARAGE EQUIPMENT						
	POWER OPERATED EQUIPMENT						
	COMMUNICATION EQUIPMENT						
	MISCELLANEOUS	17 - S2.5	25				

* Curve shown is interim survivor curve.

Service Life and Net Salvage Statistics - Electric

		Chugach Electric Association,		Alliant - Iowa		Alliant - Minnesota	
	Client:	Chugach Electric Association,		Alliant - Iowa		Alliant - Minnesota	
	Study date:						
	Study date:	2002		2004		2004	
	Procedure / Basis:	ASL / Rem. Life		ASL / Rem. Life		ASL / Rem. Life	
FERC Acct.	Description	Survivor Curve	Net Salvage Percent	Survivor Curve	Net Salvage Percent	Survivor Curve	Net Salvage Percent
	STEAM PRODUCTION PLANT						
311	STRUCTURES AND IMPROVEMENTS	65 - R1.5*	(5)	100 - S2.5*	(20)	100 - S2*	(20)
	LANDFILL						
312	BOILER PLANT EQUIPMENT	65 - R2.5*	(10)	70 - R2.5*	(15)	75 - S2*	(10)
	COMBUSTION INITIATIVE			SQUARE*	0		
	UNIT COAL TRAIN						
	POWER OPERATED						
	UNCLASSIFIED						
	SCRUBBERS						
313	ENGINES & GENERATORS						
314	TURBOGENERATOR UNITS	65 - R3*	(5)	60 - R3*	(10)	75 - S3*	(40)
315	ACCESSORY ELECTRIC EQUIPMENT	30 - R3*	(5)	65 - R4*	(5)	65 - R4*	0
316	MISCELLANEOUS PLANT EQUIPMENT	35 - R2.5*	0	55 - R2.5*	0	60 - S1.5*	0
	COMBUSTION INITIATIVE			SQUARE*	0		
	AIR MONITORING EQUIPMENT						
	FURNITURE						
	DATA PROCESSING EQUIPMENT						
	CARS						
	TOOLS, SHOP AND GARAGE EQUIPMENT						
	POWER OPERATED EQUIPMENT						
	COMMUNICATION EQUIPMENT						
	MISCELLANEOUS						

* Curve shown is interim survivor curve.

Service Life and Net Salvage Statistics - Electric

		Client:	Anchorage Municipal Power &		Avista Corporation		Allegheny Energy - Supply	
		Study date:						
		Study date:	2004		2004		2005	
		Procedure / Basis:	ASL / Rem. Life		ASL / Rem. Life		ELG / Rem. Life	
FERC Acct.	Description		Survivor Curve	Net Salvage Percent	Survivor Curve	Net Salvage Percent	Survivor Curve	Net Salvage Percent
	STEAM PRODUCTION PLANT							
311	STRUCTURES AND IMPROVEMENTS		90 - S1*	(5)	65 - S1.5*	(15)	100 - R2.5*	0
	LANDFILL				50 S3*	0		
312	BOILER PLANT EQUIPMENT		60 - S1*	(10)	60 - R1*	(20)	80 - R0.5*	0
	COMBUSTION INITIATIVE		30 - S1*	(5)				
	UNIT COAL TRAIN							
	POWER OPERATED							
	UNCLASSIFIED							
	SCRUBBERS		25 - R0.5*	(10)				
313	ENGINES & GENERATORS		25 - R0.5*	(10)				
314	TURBOGENERATOR UNITS		25 - R0.5*	(5)	50 - O1*	(10)	60 - R0.5*	0
315	ACCESSORY ELECTRIC EQUIPMENT		20 - S0*	0	55 - S1.5*	(5)	65 - R1.5*	0
316	MISCELLANEOUS PLANT EQUIPMENT				50 - R2*	0	65 - R2*	0
	COMBUSTION INITIATIVE							
	AIR MONITORING EQUIPMENT							
	FURNITURE							
	DATA PROCESSING EQUIPMENT							
	CARS							
	TOOLS, SHOP AND GARAGE EQUIPMENT							
	POWER OPERATED EQUIPMENT							
	COMMUNICATION EQUIPMENT							
	MISCELLANEOUS							

* Curve shown is interim survivor curve.

Service Life and Net Salvage Statistics - Electric

	Client:	East Kentucky Power Cooperative		Manitoba Hydro		Maritime Electric Company	
	Study date:						
	Study date:	2005		2005		2005	
	Procedure / Basis:	ELG / Rem. Life		ASL / Rem. Life		ASL / Whole Life	
FERC Acct.	**Description**	**Survivor Curve**	**Net Salvage Percent**	**Survivor Curve**	**Net Salvage Percent**	**Survivor Curve**	**Net Salvage Percent**
	STEAM PRODUCTION PLANT						
311	STRUCTURES AND IMPROVEMENTS	80 - S1	0			120 - S0*	(10)
	LANDFILL						
312	BOILER PLANT EQUIPMENT	55 - S0.5	0	65 - R3*	0	60 - S0*	(10)
	COMBUSTION INITIATIVE						
	UNIT COAL TRAIN						
	POWER OPERATED						
	UNCLASSIFIED						
	SCRUBBERS						
313	ENGINES & GENERATORS						
314	TURBOGENERATOR UNITS	50 - S1	0			100 - S0*	(10)
315	ACCESSORY ELECTRIC EQUIPMENT	60 - S2	0			80 - R2*	(10)
316	MISCELLANEOUS PLANT EQUIPMENT	35 - R2	0			70 - L0*	(10)
	COMBUSTION INITIATIVE						
	AIR MONITORING EQUIPMENT						
	FURNITURE						
	DATA PROCESSING EQUIPMENT						
	CARS						
	TOOLS, SHOP AND GARAGE EQUIPMENT						
	POWER OPERATED EQUIPMENT						
	COMMUNICATION EQUIPMENT						
	MISCELLANEOUS						

* Curve shown is interim survivor curve.

Service Life and Net Salvage Statistics - Electric

		Client:	Allegheny Energy - Monongahela		Nevada Power Company		Puget Sound Energy	
		Study date:						
		Study date:	2005		2005		2005	
		Procedure / Basis:	ASL / Rem. Life		ASL / Rem. Life		ASL / Rem. Life	
FERC Acct.	Description		Survivor Curve	Net Salvage Percent**	Survivor Curve	Net Salvage Percent	Survivor Curve	Net Salvage Percent
	STEAM PRODUCTION PLANT							
311	STRUCTURES AND IMPROVEMENTS		100 - R2.5	(30)	125 - R2	(9)	125 - R2*	(10)
	LANDFILL							
312	BOILER PLANT EQUIPMENT		80 - R0.5	(30)	65 - R1.5	(9)	65 - R1.5*	(10)
	COMBUSTION INITIATIVE							
	UNIT COAL TRAIN							
	POWER OPERATED							
	UNCLASSIFIED							
	SCRUBBERS							
313	ENGINES & GENERATORS							
314	TURBOGENERATOR UNITS		60 - R0.5	(30)	100 - R1	(9)	70 - R2*	(10)
315	ACCESSORY ELECTRIC EQUIPMENT		65 - R1.5	(30)	75 - S1.5	(9)	70 - S2*	
316	MISCELLANEOUS PLANT EQUIPMENT		65 - R2	(30)	35 - S0	(9)	45 - R0.5*	
	COMBUSTION INITIATIVE							
	AIR MONITORING EQUIPMENT							
	FURNITURE							
	DATA PROCESSING EQUIPMENT							
	CARS							
	TOOLS, SHOP AND GARAGE EQUIPMENT							
	POWER OPERATED EQUIPMENT							
	COMMUNICATION EQUIPMENT							
	MISCELLANEOUS							

* Curve shown is interim survivor curve.

Service Life and Net Salvage Statistics - Electric

		Sierra Pacific Power Company		AmerenUE		Alliant Energy - Wisconsin Power	
	Client:	Sierra Pacific Power Company		AmerenUE		Alliant Energy - Wisconsin Power	
	Study date:						
	Study date:	2004		2005		2005	
	Procedure / Basis:	ASL / Rem. Life		ASL / Rem. Life		ASL / Rem. Life	
FERC Acct.	Description	Survivor Curve	Net Salvage Percent	Survivor Curve	Net Salvage Percent ++	Survivor Curve	Net Salvage Percent +++
	STEAM PRODUCTION PLANT						
311	STRUCTURES AND IMPROVEMENTS	125 - R2*	(30)	120 - S0*	(20)	100 - R2*	(40)
	LANDFILL						
312	BOILER PLANT EQUIPMENT	60 - R2*	(30)	60 - L0.5*	(20)	75 - R1.5*	(40)
	COMBUSTION INITIATIVE						
	UNIT COAL TRAIN			22 - R3	30	25 - R2	25
	POWER OPERATED					20 - L2	0
	UNCLASSIFIED					40 - S2	0
	SCRUBBERS						
313	ENGINES & GENERATORS						
314	TURBOGENERATOR UNITS	70 - R2*	(30)	70 - L0.5*	(20)	50 - R2*	(40)
315	ACCESSORY ELECTRIC EQUIPMENT	60 - S1.5*	(30)	90 - R1*	(20)	50 - L2*	(40)
316	MISCELLANEOUS PLANT EQUIPMENT	50 - R1.5*	(30)	60 - O1*	(20)	60 - R1.5*	(40)
	COMBUSTION INITIATIVE					10 - SQ	0
	AIR MONITORING EQUIPMENT					15 - S3	0
	FURNITURE					20 - SQ	0
	DATA PROCESSING EQUIPMENT					7 - SQ	0
	CARS					8 - L2.5	0
	TOOLS, SHOP AND GARAGE EQUIPMENT					20 - L2	0
	POWER OPERATED EQUIPMENT					20 - L2	0
	COMMUNICATION EQUIPMENT					15 - SQ	0
	MISCELLANEOUS					25 - SQ	0

* Curve shown is interim survivor curve.

Service Life and Net Salvage Statistics - Electric

Client:	**AmerenCILCO**
Study date:	
Study date:	**2004**
Procedure / Basis:	**ASL / Rem. Life**

FERC Acct.	Description	Survivor Curve	Net Salvage Percent
	STEAM PRODUCTION PLANT		
311	STRUCTURES AND IMPROVEMENTS	SQUARE*	0
	LANDFILL		
312	BOILER PLANT EQUIPMENT	SQUARE*	0
	COMBUSTION INITIATIVE		
	UNIT COAL TRAIN		
	POWER OPERATED		
	UNCLASSIFIED		
	SCRUBBERS		
313	ENGINES & GENERATORS		
314	TURBOGENERATOR UNITS	SQUARE*	0
315	ACCESSORY ELECTRIC EQUIPMENT	SQUARE*	0
316	MISCELLANEOUS PLANT EQUIPMENT		
	COMBUSTION INITIATIVE		
	AIR MONITORING EQUIPMENT		
	FURNITURE		
	DATA PROCESSING EQUIPMENT		
	CARS		
	TOOLS, SHOP AND GARAGE EQUIPMENT		
	POWER OPERATED EQUIPMENT		
	COMMUNICATION EQUIPMENT		
	MISCELLANEOUS		

* Curve shown is interim survivor curve.

KENTUCKY UTILITIES COMPANY
LOUISVILLE GAS AND ELECTRIC COMPANY

Response to First Data Request of
Kentucky Industrial Utility Customers, Inc.
Dated October 8, 2009

Case No. 2009-00329

Question No. 1.3

Witness: John J. Spanos

Q-1.3. Please disaggregate the net salvage percent into interim and terminal net salvage percentages by plant account.

A-1.3. The net salvage percent set forth by Mr. Spanos in his letter includes only interim net salvage. This is consistent with the net salvage percents of the other KU and LG&E units.

KENTUCKY UTILITIES COMPANY
LOUISVILLE GAS AND ELECTRIC COMPANY

Response to First Data Request of
Kentucky Industrial Utility Customers, Inc.
Dated October 8, 2009

Case No. 2009-00329

Question No. 1.4

Witness: John J. Spanos

Q-1.4. To the extent Gannet Fleming relied on parameters underlying the present depreciation rates for TC1 to develop its proposed parameters and depreciation rates for TC2, please provide all workpapers developed by and a copy of all source documents relied on by Gannet Fleming to develop the parameters underlying the present depreciation rates for TC1.

A-1.4. The parameters for TC1 are set forth in the LG&E Depreciation Study, Case No. 2007-00564 on pages III-4 and III-5. Please see the attached sheets.

LOUISVILLE GAS AND ELECTRIC
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, 2006

	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)
	DEPRECIABLE PLANT								
	STEAM PRODUCTION PLANT								
311.00	STRUCTURES AND IMPROVEMENTS								
	CANE RUN UNIT 1	100-S1.5 •	(10)	4,233,981.48	4,657,380	0	0	-	-
	CANE RUN UNIT 2	100-S1.5 •	(10)	2,102,942.00	2,313,236	0	0	-	-
	CANE RUN UNIT 3	100-S1.5 •	(10)	3,532,140.00	3,885,354	0	0	-	-
	CANE RUN UNIT 4	100-S1.5 •	(10)	3,819,018.36	3,652,193	548,727	48,090	1.26	11.4
	CANE RUN-SO2 UNIT 4	100-S1.5 •	(10)	760,360.00	740,943	95,453	8,419	1.11	11.3
	CANE RUN UNIT 5	100-S1.5 •	(10)	6,165,918.13	4,902,105	1,880,404	123,433	2.00	15.2
	CANE RUN-SO2 UNIT 5	100-S1.5 •	(10)	1,696,435.00	1,439,174	426,905	28,165	1.66	15.2
	CANE RUN UNIT 6	100-S1.5 •	(10)	19,346,501.56	14,289,215	6,991,936	429,786	2.22	16.3
	CANE RUN-SO2 UNIT 6	100-S1.5 •	(10)	1,894,852.32	1,428,902	655,435	40,312	2.13	16.3
	MILL CREEK UNIT 1	100-S1.5 •	(10)	19,168,217.08	14,873,144	6,211,894	327,762	1.71	19.0
	MILL CREEK-SO2 UNIT 1	100-S1.5 •	(10)	1,716,995.50	1,323,045	565,650	29,820	1.74	19.0
	MILL CREEK UNIT 2	100-S1.5 •	(10)	10,812,787.99	8,830,804	3,063,264	162,336	1.50	18.9
	MILL CREEK-SO2 UNIT 2	100-S1.5 •	(10)	1,393,404.00	1,032,477	500,268	26,311	1.89	19.0
	MILL CREEK UNIT 3	100-S1.5 •	(10)	24,963,587.02	16,492,690	10,967,256	394,688	1.58	27.8
	MILL CREEK-SO2 UNIT 3	100-S1.5 •	(10)	362,867.00	244,888	154,266	5,567	1.53	27.7
	MILL CREEK UNIT 4	100-S1.5 •	(10)	60,311,484.02	33,672,363	32,670,270	1,158,787	1.92	28.2
	MILL CREEK-SO2 UNIT 4	100-S1.5 •	(10)	5,307,313.20	3,112,165	2,725,880	96,858	1.82	28.1
	TRIMBLE COUNTY - UNIT 1	100-S1.5 •	(10)	160,498,043.70	77,938,729	98,609,119	3,452,800	2.15	28.6
	TRIMBLE COUNTY - SO2 UNIT 1	100-S1.5 •	(10)	511,308.94	218,077	344,362	12,010	2.35	28.7
	TOTAL ACCOUNT 311 - STRUCTURES AND IMPROVEMENTS			328,598,157.30	195,046,884	166,411,089	6,345,144	1.93	26.2
312.00	BOILER PLANT EQUIPMENT								
	CANE RUN LOCOMOTIVE	25-R2	20	51,549.42	33,262	7,978	2,470	4.79	3.2
	CANE RUN LOCOMOTIVE - RAILCARS	25-R2	20	1,501,772.81	531,310	670,108	53,867	3.59	12.4
	CANE RUN UNIT 1	45-R1.5 •	(30)	1,053,742.00	1,369,865	0	0	-	-
	CANE RUN UNIT 2	45-R1.5 •	(30)	132,637.00	172,688	0	0	-	-
	CANE RUN UNIT 3	45-R1.5 •	(30)	711,484.00	924,929	0	0	-	-
	CANE RUN UNIT 4	45-R1.5 •	(30)	30,277,226.79	18,288,583	21,071,814	2,016,040	6.66	10.5
	CANE RUN-SO2 UNIT 4	45-R1.5 •	(30)	17,091,727.81	11,881,513	10,337,734	981,260	5.74	10.5
	CANE RUN UNIT 5	45-R1.5 •	(30)	34,767,159.48	13,504,758	31,692,551	2,332,399	6.71	13.6
	CANE RUN-SO2 UNIT 5	45-R1.5 •	(30)	28,107,437.90	19,098,338	17,441,331	1,298,757	4.62	13.4
	CANE RUN UNIT 6	45-R1.5 •	(30)	47,135,674.34	22,778,252	38,498,125	2,726,434	5.78	14.1
	CANE RUN-SO2 UNIT 6	45-R1.5 •	(30)	32,184,156.61	19,088,684	22,750,722	1,600,158	4.97	14.2
	MILL CREEK-LOCOMOTIVE	25-R2	20	613,424.43	364,410	126,329	24,762	4.04	5.1
	MILL CREEK-LOCOMOTIVE RAILCARS	25-R2	20	3,593,111.63	1,332,957	1,541,532	128,750	3.58	12.0
	MILL CREEK UNIT 1	45-R1.5 •	(30)	47,559,197.98	26,339,437	35,487,522	2,246,257	4.72	15.8
	MILL CREEK-SO2 UNIT 1	45-R1.5 •	(30)	42,349,730.64	20,691,298	34,363,352	2,101,740	4.96	16.3
	MILL CREEK UNIT 2	45-R1.5 •	(30)	47,357,145.83	21,853,684	39,710,608	2,472,523	5.22	16.1
	MILL CREEK-SO2 UNIT 2	45-R1.5 •	(30)	34,424,936.00	18,284,740	26,467,678	1,621,216	4.71	16.3
	MILL CREEK UNIT 3	45-R1.5 •	(30)	137,324,677.88	48,484,795	130,037,286	6,148,975	4.48	21.1
	MILL CREEK-SO2 UNIT 3	45-R1.5 •	(30)	63,097,998.79	21,582,229	60,445,168	2,762,215	4.38	21.9
	MILL CREEK UNIT 4	45-R1.5 •	(30)	237,604,471.44	82,876,873	226,008,940	10,573,987	4.45	21.4
	MILL CREEK-SO2 UNIT 4	45-R1.5 •	(30)	113,648,645.53	44,103,121	103,640,119	4,709,202	4.14	22.0
	TRIMBLE COUNTY - UNIT 1	45-R1.5 •	(30)	246,928,938.61	102,820,597	218,187,022	9,975,426	4.04	21.9
	TRIMBLE COUNTY - SO2 UNIT 1	45-R1.5 •	(30)	63,159,341.63	26,413,284	55,693,861	2,590,120	4.10	21.5
	TOTAL ACCOUNT 312 - BOILER PLANT EQUIPMENT			1,230,676,390.55	522,819,607	1,074,179,780	56,366,558	4.58	19.1

Attachment to Response to Question No. 1.4
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Spanos

LOUISVILLE GAS AND ELECTRIC
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, 2006

	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)
314.00	TURBOGENERATOR UNITS								
	CANE RUN UNIT 1	50-S1.5 •	(10)	106,008.99	116,610	0	0	-	-
	CANE RUN UNIT 2	50-S1.5 •	(10)	19,999.00	21,999	0	0	-	-
	CANE RUN UNIT 3	50-S1.5 •	(10)	581,177.00	639,295	0	0	-	-
	CANE RUN UNIT 4	50-S1.5 •	(10)	9,122,982.05	6,696,016	3,339,265	309,760	3.40	10.8
	CANE RUN UNIT 5	50-S1.5 •	(10)	7,375,364.74	5,731,823	2,381,080	178,552	2.42	13.3
	CANE RUN UNIT 6	50-S1.5 •	(10)	14,984,949.73	8,626,498	7,856,948	519,788	3.47	15.1
	MILL CREEK UNIT 1	50-S1.5 •	(10)	14,332,084.36	10,582,040	5,183,252	330,036	2.30	15.7
	MILL CREEK UNIT 2	50-S1.5 •	(10)	16,626,879.81	11,208,486	7,081,084	434,898	2.62	16.3
	MILL CREEK UNIT 3	50-S1.5 •	(10)	27,112,329.06	16,947,408	12,876,153	618,480	2.28	20.8
	MILL CREEK UNIT 4	50-S1.5 •	(10)	42,108,819.15	23,847,796	22,471,905	1,032,197	2.45	21.8
	TRIMBLE COUNTY - UNIT 1	50-S1.5 •	(10)	66,954,098.52	32,201,467	41,448,022	1,796,816	2.68	23.1
	TOTAL ACCOUNT 314 - TURBOGENERATOR UNITS			199,324,692.41	116,619,458	102,637,709	5,220,547	2.62	19.7
315.00	ACCESSORY ELECTRIC EQUIPMENT								
	CANE RUN UNIT 1	50-S2 •	(5)	1,891,012.00	1,985,563	0	0	-	-
	CANE RUN UNIT 2	50-S2 •	(5)	1,277,223.00	1,341,084	0	0	-	-
	CANE RUN UNIT 3	50-S2 •	(5)	767,325.00	805,691	0	0	-	-
	CANE RUN UNIT 4	50-S2 •	(5)	5,474,319.06	3,637,429	2,110,606	185,974	3.40	11.3
	CANE RUN-SO2 UNIT 4	50-S2 •	(5)	987,949.00	925,415	111,931	11,019	1.12	10.2
	CANE RUN UNIT 5	50-S2 •	(5)	6,856,291.05	3,999,065	3,200,040	214,025	3.12	15.0
	CANE RUN-SO2 UNIT 5	50-S2 •	(5)	2,216,498.98	1,831,913	495,413	36,996	1.67	13.4
	CANE RUN UNIT 6	50-S2 •	(5)	8,571,566.71	5,058,977	3,941,167	251,391	2.93	15.7
	CANE RUN-SO2 UNIT 6	50-S2 •	(5)	2,124,667.00	1,756,831	474,070	34,157	1.61	13.9
	MILL CREEK UNIT 1	50-S2 •	(5)	14,425,285.62	7,663,999	7,482,552	410,132	2.84	18.2
	MILL CREEK-SO2 UNIT 1	50-S2 •	(5)	5,541,695.00	4,219,198	1,599,582	99,693	1.80	16.0
	MILL CREEK UNIT 2	50-S2 •	(5)	6,428,715.51	4,407,033	2,343,119	136,760	2.13	17.1
	MILL CREEK-SO2 UNIT 2	50-S2 •	(5)	4,505,053.40	3,408,426	1,321,880	82,399	1.83	16.0
	MILL CREEK UNIT 3	50-S2 •	(5)	13,482,711.00	9,659,013	4,297,834	221,163	1.64	19.4
	MILL CREEK-SO2 UNIT 3	50-S2 •	(5)	2,531,773.00	1,869,107	789,255	41,010	1.62	19.2
	MILL CREEK UNIT 4	50-S2 •	(5)	20,755,277.95	13,839,245	7,953,796	383,791	1.85	20.7
	MILL CREEK-SO2 UNIT 4	50-S2 •	(5)	5,864,978.52	4,000,224	2,158,003	105,878	1.81	20.4
	TRIMBLE COUNTY - UNIT 1	50-S2 •	(5)	56,269,846.00	28,932,620	30,150,719	1,281,579	2.26	23.5
	TRIMBLE COUNTY - SO2 UNIT 1	50-S2 •	(5)	2,736,920.00	1,409,344	1,464,422	62,279	2.28	23.5
	TOTAL ACCOUNT 315 - ACCESSORY ELECTRIC EQUIPMENT			162,709,107.80	100,950,177	69,894,389	3,558,246	2.19	19.6
316.00	MISCELLANEOUS PLANT EQUIPMENT								
	CANE RUN UNIT 1	40-S2 •	(5)	38,746.00	40,683	0	0	-	-
	CANE RUN UNIT 3	40-S2 •	(5)	11,665.00	12,248	0	0	-	-
	CANE RUN UNIT 4	40-S2 •	(5)	71,143.38	22,270	52,430	4,624	6.50	11.3
	CANE RUN-SO2 UNIT 4	40-S2 •	(5)	6,464.00	4,941	1,846	204	3.16	9.0
	CANE RUN UNIT 5	40-S2 •	(5)	80,865.51	16,978	67,930	4,473	5.53	15.2
	CANE RUN-SO2 UNIT 5	40-S2 •	(5)	47,299.00	32,551	17,112	1,478	3.12	11.6
	CANE RUN UNIT 6	40-S2 •	(5)	2,707,943.48	981,898	1,861,444	122,063	4.51	15.2
	CANE RUN-SO2 UNIT 6	40-S2 •	(5)	31,569.00	22,215	10,933	942	2.98	11.6
	MILL CREEK UNIT 1	40-S2 •	(5)	696,198.16	393,771	337,237	23,454	3.37	14.4
	MILL CREEK UNIT 2	40-S2 •	(5)	112,007.80	70,170	47,439	3,474	3.10	13.7
	MILL CREEK UNIT 3	40-S2 •	(5)	318,625.00	205,205	129,352	8,883	2.79	14.6
	MILL CREEK UNIT 4	40-S2 •	(5)	5,198,564.77	1,641,175	3,817,319	170,528	3.28	22.4
	MILL CREEK-SO2 UNIT 4	40-S2 •	(5)	53,006.66	26,501	29,156	1,602	3.02	18.2
	TRIMBLE COUNTY - UNIT 1	40-S2 •	(5)	2,574,446.81	1,009,526	1,693,644	81,361	3.16	20.8
	TOTAL ACCOUNT 316 - MISCELLANEOUS PLANT EQUIPMENT			11,948,544.57	4,480,132	8,065,842	423,086	3.54	19.1
	TOTAL STEAM PRODUCTION PLANT			1,933,256,892.63	939,916,258	1,421,188,809	71,913,581		

KENTUCKY UTILITIES COMPANY
LOUISVILLE GAS AND ELECTRIC COMPANY

Response to First Data Request of
Kentucky Industrial Utility Customers, Inc.
Dated October 8, 2009

Case No. 2009-00329

Question No. 1.5

Witness: John J. Spanos

Q-1.5. Please describe each step in the process whereby Gannet Fleming developed, evaluated and decided on the net negative salvage component of the proposed TC2 depreciation rates by plant account. Separately describe the process for interim net negative salvage and for terminal net negative salvage. Identify and describe all assumptions, data sources, source documents and computations/workpapers obtained, developed and/or relied on for each step of the process.

A-1.5. Mr. Spanos evaluated net salvage percents by account of many comparable units across the United States. This information is coupled with the estimates utilized for KU and LG&E. The estimates for TC1 and LG&E were considered the dominant component when determining the proposed net salvage percent for each account of TC2. Only interim net salvage is considered in the proposed net salvage percent.

KENTUCKY UTILITIES COMPANY
LOUISVILLE GAS AND ELECTRIC COMPANY

Response to First Data Request of
Kentucky Industrial Utility Customers, Inc.
Dated October 8, 2009

Case No. 2009-00329

Question No. 1.6

Witness: John J. Spanos

Q-1.6. Please provide a copy of all dismantling studies and/or analyses performed by or relied on by Gannet Fleming in the derivation of the net salvage component of the proposed TC2 depreciation rates in total and by plant account.

A-1.6. There were no dismantling studies considered or relied upon by Gannett Fleming for the proposed estimate for TC2. Terminal net salvage is not part of the estimate.

KENTUCKY UTILITIES COMPANY
LOUISVILLE GAS AND ELECTRIC COMPANY

Response to First Data Request of
Kentucky Industrial Utility Customers, Inc.
Dated October 8, 2009

Case No. 2009-00329

Question No. 1.7

Witness: John J. Spanos

Q-1.7. Please provide the dollar amount of terminal net salvage developed by or relied on by Gannet Fleming in the derivation of the net salvage component of the proposed TC2 depreciation rates in total and by plant account.

A-1.7. There is no dollar amount of terminal net salvage relied upon by Gannett Fleming because there is no component of terminal net salvage in the proposed TC2 depreciation rates.

KENTUCKY UTILITIES COMPANY
LOUISVILLE GAS AND ELECTRIC COMPANY

Response to First Data Request of
Kentucky Industrial Utility Customers, Inc.
Dated October 8, 2009

Case No. 2009-00329

Question No. 1.8

Witness: John J. Spanos

Q-1.8. Please provide a copy of all analyses and/or comparative quantifications in dollars, dollars/kW and/or percentages used by and relied on by Gannet Fleming to assess the reasonableness of the interim and terminal net negative salvage components of the proposed TC2 depreciation rates by plant account.

A-1.8. There was no analysis or quantifications in dollars, dollar/KW and/or percentages used by and relied on by Gannett Fleming to assess terminal net negative salvage components of the proposed TC2 depreciation rates.