COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

APPLICATION OF KENTUCKY	)	
UTILITIES COMPANY FOR AN	)	CASE NO. 2009-00548
ADJUSTMENT OF BASE RATES	)	

VOLUME 2 OF 5

RESPONSE TO FILING REQUIREMENTS listed in 807 KAR 5:001 SECTION 10(6)(l) through 807 KAR 5:001 SECTION 10(6)(q)

Filed: January 29, 2010

Kentucky Utilities Company
Case No. 2009-00548
Historical Test Period Filing Requirements
Table of Contents

Kentucky Utilities Company
Case No. 2009-00548
Historical Test Period Filing Requirements
Table of Contents

Kentucky Utilities Company
Case No. 2009-00548
Historical Test Period Filing Requirements
Table of Contents

Vol. No.	Tab No.	Filing Requirement	Description	Sponsoring Witness
1	10	807 KAR 5:001 Section 10(2)	*Notice of Intent. Utilities with gross annual revenues greater than $1,000,000 shall file with the commission a written notice of intent to file a rate application at least four (4) weeks prior to filing their application. The notice of intent shall state whether the rate application shall be supported by a historical test period or a fully forecasted test period. This notice shall be served upon the Attorney General, Utility Intervention and Rate Division.*	Mr. Bellar
1	11	807 KAR 5:001 Section 10(3)	*Form of notice to customers. Every utility filing an application pursuant to this section shall notify all affected customers in the manner prescribed herein. The notice shall include the following information: (a) The amount of the change requested in both dollar amounts and percentage change for each customer classification to which the proposed rate change will apply; (b) The present rates and the proposed rates for each customer class to which the proposed rates would apply; (c) Electric, gas, water and sewer utilities shall include the effect upon the average bill for each customer class to which the proposed rate change will apply; (d) Local exchange companies shall include the effect upon the average bill for each customer class for the proposed rate change in basic local service; (e) A statement that the rates contained in this notice are the rates proposed by (name of utility); however, the Public Service Commission may order rates to be charged that differ from the proposed rates contained in this notice; (f) A statement that any corporation, association, or person with a substantial interest in the matter may, by written request, within thirty (30) days after publication or mailing of this notice of the proposed rate changes request to intervene; intervention may be granted beyond the thirty (30) day period for good cause shown; (g) A statement that any person who has been granted intervention by the commission may obtain copies of the rate application and any other filings made by the utility by contacting the utility through a name and address and phone number stated in this notice; (h) A statement that any person may examine the rate application and any other filings made by the utility at the main office of the utility or at the commission's office indicating the addresses and telephone numbers of both the utility and the commission; and (i) The commission may grant a utility with annual gross revenues greater than $1,000,000, upon written request, permission to use an abbreviated form of published notice of the proposed rates provided the notice includes a coupon which may be used to obtain all of the information required herein.*	Mr. Bellar

Kentucky Utilities Company
Case No. 2009-00548
Historical Test Period Filing Requirements
Table of Contents

Kentucky Utilities Company
Case No. 2009-00548
Historical Test Period Filing Requirements
Table of Contents

Kentucky Utilities Company
Case No. 2009-00548
Historical Test Period Filing Requirements
Table of Contents

Kentucky Utilities Company
Case No. 2009-00548
Historical Test Period Filing Requirements
Table of Contents

Kentucky Utilities Company
Case No. 2009-00548
Historical Test Period Filing Requirements
Table of Contents

Kentucky Utilities Company
Case No. 2009-00548
Historical Test Period Filing Requirements
Table of Contents

Vol. No.	Tab No.	Filing Requirement	Description	Sponsoring Witness
3	46	807 KAR 5:001 Section 10(7)(e)	*Upon good cause shown, a utility may request pro forma adjustments for known and measurable changes to ensure fair, just and reasonable rates based on the historical test period. The following information shall be filed with applications requesting pro forma adjustments or a statement explaining why the required information does not exist and is not applicable to the utility's application: (e) The number of customers to be added to the test period-end level of customers and the related revenue requirements impact for all pro forma adjustments with complete details and supporting work papers.*	Mr. Seelye

Kentucky Utilities Company
Case No. 2009-00548
Historical Test Period Filing Requirements

Filing Requirement
807 KAR 5:001 Section 10(6)(l)
Sponsoring Witness: Valerie L. Scott

Description of Filing Requirement:

The most recent Federal Energy Regulatory Commission or Federal Communication Commission audit reports.

Response:

The most recent Federal Energy Regulatory Commission audit report relating to KU's electric business is attached. The Federal Communication Commission does not audit KU and, therefore, no such audit reports exist.

FERC Audit Report – July 17, 2006

FEDERAL ENERGY REGULATORY COMMISSION
WASHINGTON, D.C. 20426

In Reply Refer To:
Office of Enforcement
Docket No. PA05-9-000
July 17, 2006

Michael S. Beer
Vice President, Federal Regulation and Policy
LG&E Energy Services, Inc.
220 West Main Street
Louisville, KY 40202

Dear Mr. Beer:

1. The Division of Audits within the Office of Enforcement (OE) has completed the audit of LG&E Energy LLC (LG&E) for the period from January 1, 2003 to December 31, 2005. The enclosed audit report explains our audit findings and recommendations.

2. On June 29, 2006, you notified us that LG&E agreed with our audit findings and recommendations. I hereby approve and direct the recommended corrective actions. A copy of your response is included as an Appendix to this audit report.

3. LG&E should file an implementation plan within 30 days of the date of this letter order and submit quarterly filings describing LG&E's progress completing each corrective action, including dates it has completed each corrective action. The filings should be made no later than 30 days after the end of each calendar quarter, beginning with the first quarter after this audit report is issued, and continuing until all the corrective actions are completed.

4. The Commission delegated the authority to act on this matter to the Director of OE under 18 C.F.R. § 375.314 (2006). This letter order constitutes final agency action. Your Company may file a request for rehearing with the Commission within 30 days of the date of this order under 18 C.F.R. § 385.713 (2006).

5. This letter order is without prejudice to the Commission's right to require hereafter any adjustments it may consider proper from additional information that may come to its attention.

6. I appreciate the courtesies extended to the auditors. If you have any questions, please contact Mr. Bryan K. Craig, Director, Division of Audits at (202) 502-8741.

Sincerely,

Susan J. Court

Susan J. Court
Director
Office of Enforcement

Enclosure

FEDERAL ENERGY REGULATORY COMMISSION

Audit Period: January 1, 2003 through December 31, 2005

Audit of Code of Conduct, Standards of Conduct, Market-Based Rate Tariff, and MISO's Open Access Transmission Tariff at LG&E Energy LLC

Audit Report

OFFICE OF ENFORCEMENT
DIVISION OF AUDITS

Docket No. PA05-9-000 **Date: July 17, 2006**

TABLE OF CONTENTS

I. EXECUTIVE SUMMARY

A. Overview

The Office of Enforcement (OE)[1] has completed an audit of the operations of LG&E Energy LLC (LG&E).[2] For purposes of the audit, the relevant parts of LG&E's corporate structure included:

- The two utilities (Louisville Gas & Electric Company and Kentucky Utilities Company), each of which operates a system control center,
- LG&E's service company (LG&E Energy Services, Inc.), and
- LG&E's Marketing and Energy Affiliates, including LG&E's wholesale merchant function (WMF) and its affiliated power marketers[3]; LG&E's principal affiliated power marketer during the audit period was LG&E Energy Marketing, Inc. (LEM).

The audit covered the period from January 1, 2003 through December 31, 2005, and focused on LG&E's compliance with:

- LG&E's Code of Conduct, which requires the physical, operational, and functional separation of LG&E's WMF and its affiliated power marketers,
- The Commission's Standards of Conduct under Order No. 2004 and 18 C.F.R. Part 358 (2005), which requires the transmission function to operate independently from LG&E's energy marketing operations,
- LG&E's market-based rate tariff, and

---

[1] On April 16, 2006, the Office of Market Oversight and Investigations changed its name to the Office of Enforcement.

[2] On December 1, 2005, LG&E Energy LLC announced it changed its name to E.ON US.

[3] *LG&E Power Mktg., Inc.*, 68 FERC ¶ 61,247 (1994); *modified on other grounds*, 69 FERC ¶ 61,153 (1994). LG&E Power Mktg.'s name was changed to LG&E Energy Marketing Inc. (LEM). *See* Notice of Name Change, Docket No. ER97-3418-000 (filed June 24, 1997).

- Midwest ISO (MISO) Open Access Transmission Tariff (OATT) §28.6 Restrictions on Use of Service; §30.1 Designation of Network Resources; §30.4 Operation of Network Resources; and §30.7 Limitation on Designation of Network Resources.

B. Summary of Compliance Findings

Our audit findings are based on materials provided by LG&E in response to data requests, interviews with LG&E staff members, site visits, and a review of publicly available documents. LG&E has been very cooperative throughout the audit.

Based on our examination of the Code of Conduct, Standards of Conduct, Market-Based Rate Tariff, and MISO's OATT at LG&E, we identified nine areas of non-compliance.

<u>Code of Conduct Compliance</u>

- *Functional, Physical, and Operational Separation of LG&E's WMF and Affiliated Power Marketer*: LG&E's WMF and its principal affiliated power marketer (LEM) were not functionally, physically, and operationally separate to the maximum extent practical, as required by LG&E's Code of Conduct. Both WMF and LEM functionally reported to the same company officer and LEM shared physical facilities with WMF traders and with mid-office and back-office functions for the WMF. WMF and LEM operationally shared a telephone recording system to capture trading and dispatch conversations.

- *Sharing of Market Information*: LG&E's WMF shared market information with its principal affiliated power marketer (LEM) through presentations at joint staff meetings, in violation of LG&E's Code of Conduct. Also, the password access controls to the shared Energy Management System (EMS) were inconsistent with LG&E's password security policy.

- *Posting of Information on Sales to Affiliates at Market-Based Rates*: LG&E was required to post on an electronic bulletin board (EBB) information on energy sales at market-based rates from its WMF to its affiliated power marketer (LEM). LG&E's Code of Conduct required the price of such sales to be no lower than the rate charged to non-affiliates, and required simultaneous postings on an EBB of WMF's offers to sell to LEM and WMF's actual sales to LEM. Our review of LG&E's archived EBB postings disclosed that LG&E's EBB was not accessible to non-affiliated market participants for a period of time, and the information that LG&E posted on the EBB was not consistent with the requirements in LG&E's Code of Conduct.

Docket No. PA05-9-000

Standards of Conduct Compliance

- *Disclosures of Transmission and Customer Information*: LG&E transmission employees improperly disclosed non-public transmission and customer information to employees of its WMF that was not contemporaneously available to the public, and failed to post in a timely manner the information disclosure on OASIS: (1) on at least three occasions, LG&E transmission employees disclosed real-time transmission system status information to LG&E Energy and Marketing affiliate employees during telephone calls concerning generation re-dispatch; (2) on at least one occasion, LG&E made transmission expansion planning information available to marketing employees; and (3) on a monthly basis through February 2005, a transmission employee sent e-mails to a marketing employee containing load data of third-party customers.

- *Standards of Conduct Training*: The scope of LG&E's Standards of Conduct training program was inconsistent with Commission regulations and with LG&E's training implementation plans. More than one year after the effective date of Order No. 2004, LG&E had failed to provide Standards of Conduct training for several hundred of the employees LG&E was required to train.

- *Controls Used to Limit Access to System Control Centers*: LG&E did not follow its posted implementation procedures to control and track access by the employees of its Marketing and Energy Affiliates to LG&E's two system control centers, including the requirement that LG&E marketing employees obtain permission from the Chief Compliance Officer (CCO) before visiting the system control centers.

- *Organizational Charts*: The organizational chart postings failed to include or accurately show: detailed organizational charts for business units engaged in the sales function; the position of LG&E's Marketing and Energy Affiliates within the corporate structure; and all of the business units that are part of LG&E's service company.

- *Shared Facilities*: LG&E did not post a list of the facilities shared by the Transmission Provider and LG&E's Marketing and Energy Affiliates as required by 18 C.F.R. § 358.4(b)(2) (2005).

Market-Based Rate Tariff Compliance

- *Electric Quarterly Report Inaccuracies*: LG&E's Electric Quarterly Report (EQR) filing for the first quarter of 2005 contained inaccurate information. LG&E inaccurately reported several sales transactions from its WMF to its affiliated power marketer (LEM) and reported invalid Data Universal Numbering System (DUNS) numbers for several other customers.

C. Summary of Recommendations

Detailed recommendations are included in Sections III, IV, and V of this Audit Report that describe the compliance findings. Following is a brief summary of those recommendations. We recommend that LG&E:

- Implement its planned actions to ensure that WMF and LEM employees are functionally, physically, and operationally separate to the maximum extent practical.

- Create and implement policies and procedures to ensure that there is no exchange of market information inconsistent with LG&E's Code of Conduct, and to conduct an independent review after implementation of a new EMS system to ensure that market information (and transmission information) is not accessible to employees who should not have access to such information.

- Develop written policies and procedures regarding the use of its EBB, and develop a plan for making the EBB more accessible to non-affiliated market participants.

- Post OASIS notices for all identified disclosures of non-public transmission information. Specific recommendations include creating controls to prevent disclosure of non-public transmission and customer information as part of transmission operations, during meetings attended by transmission and marketing employees, and through e-mail exchanges of information.

- Strengthen the implementation of its training program, specifically, to develop written policies and procedures to ensure that new employees receive training, and conduct periodic reviews to ensure that all of the employees that require training are scheduled for, receive training, and are certified.

- Review and strengthen its system control center access procedures to ensure that LG&E marketing employees do not have access that differs in any way from the access available to other transmission customers.

- Revise its posted organizational charts to show the business units engaged in sales functions, the position of all Marketing and Energy Affiliates within its corporate structure, and sufficient detail to indicate that LG&E's service company is the employment mechanism for the Marketing and Energy Affiliates and the Transmission Provider.

- Revise its shared facilities postings to identify all facilities that LG&E's Marketing and Energy Affiliates share with service employees who have access to non-public transmission or customer information.

- Strengthen its written procedures to ensure that EQR filings are in compliance with Commission regulations, and to refile inaccurate EQR data identified in this Audit Report.

D. Actions Already Taken by LG&E

LG&E has already taken a number of corrective actions in response to our compliance findings to come into compliance with the Standards of Conduct and LG&E's Code of Conduct. These actions are enumerated in detail in Sections III, IV, and V of this Audit Report that describe the compliance findings.

As part of the audit scope, audit staff examined LG&E's use of network integration transmission service (NITS) for the audit period prior to April 1, 2005, the beginning of the MISO Day 2 market. After working with audit staff to perform the review of LG&E's use of NITS, LG&E committed to enhancing its "Before the Purchase System" (BPS) by creating detailed control processes to ensure its compliance with the OATT and the proper use of NITS. LG&E's BPS is a software product that determines when a bi-lateral power purchase can be reasonably expected to serve native load and can be imported using network integration transmission service. LG&E's BPS system provides traders a systematic process for determining if a purchase should be imported using NITS before purchases are made and scheduled. The BPS helps ensure LG&E's compliance with the Commission's approved uses for NITS.

E. Implementation Plan

We recommended that LG&E submit an implementation plan to the audit staff for our approval detailing LG&E's plans to comply fully with the findings and recommendations in this Audit Report. The implementation plan should describe the actions LG&E has already taken, and will take, that are consistent with and complementary to any future structural and organizational changes that LG&E may undertake.

The implementation plan should be submitted within 30 days of issuance of a Final Audit Report in this docket. In addition, LG&E shall make quarterly filings updating the audit staff of its progress on implementing the plan. The filings shall be made no later than 30 days after the end of each calendar quarter, beginning with the first quarter after this audit report is issued, and continuing until all the corrective actions are completed.

II. INTRODUCTION

A. Objectives

The overall audit objectives were to determine compliance with:

- LG&E's Code of Conduct, which requires the physical, operational, and functional separation of the utilities' WMF and its affiliated power marketers.
- The Commission's Standards of Conduct under Order No. 2004 (and prior to September 22, 2004, under Order No. 889[4]), which requires a Transmission Provider's employees engaged in transmission system operations to function independently from employees of its Marketing and Energy Affiliates.[5] Standards of Conduct compliance was also evaluated against LG&E's own implementation procedures.[6]

---

[4] *Open-Access Same-Time Information System (formerly Real-Time Information Networks) and Standards of Conduct*, Order No. 889, 61 FR 21737 (May 10, 1996), FERC Stats. & Regs., Regulations Preambles ¶ 31,035 (Apr. 24, 1996); *order on reh'g*, Order No. 889-A FR 12484 (March 14, 1997), FERC Stats. & Regs., Regulations Preambles ¶ 31,049 (March 4, 1997).

[5] *Standards of Conduct for Transmission Providers*, Order No. 2004, 68 FR 69134 (Dec. 11, 2003), FERC Stats. & Regs., Regulations Preambles ¶ 31,155 (Nov. 25, 2003), *order on reh'g*, Order No. 2004-A, 69 FR 23562 (Apr. 29, 2004), FERC Stats. & Regs., Regulations Preambles ¶ 31,161 (April 16, 2004), *order on reh'g*, Order No. 2004-B, 69 FR 48371(Aug. 10, 2004), FERC Stats. & Regs., Regulations Preambles ¶ 31,166 (Aug. 2, 2004), *order on reh'g*, Order No. 2004-C, 70 FR 284 (Jan. 4, 2005), FERC Stats. & Regs., Regulations Preambles ¶ 31,172 (Dec. 21, 2004), order on reh'g, Order No. 2004-D, 110 FERC ¶ 61,320 (2005), *appeal pending*, (D.C. Circuit Docket Nos. 04-1178, et al.)

[6] "Joint Written Procedures Implementing Standards of Conduct for Transmission Providers as Adopted by the Federal Energy Regulatory Commission in Order No. 2004, Effective September 22, 2004" (hereinafter referred to as LG&E's posted implementation procedures). We found this document on April 5, 2005, posted on http://lgeenergy.com/regulatory/lgeku_compliance_procedures.pdf.

- LG&E's market-based rate tariff.[7]

- The provisions of the MISO OATT.[8]

For purposes of evaluating compliance with the Standards of Conduct, this audit focuses primarily on the period from September 22, 2004, the effective date of Order No. 2004, to December 31, 2005. For purposes of evaluating compliance with Code of Conduct, market-based rate tariff and MISO's OATT requirements, this audit focuses primarily on the period from January 1, 2003 to December 31, 2005.

B. Scope and Methodology

The OE has completed an audit of the operations of LG&E. As part of the audit, OE conducted selective tests on data to determine LG&E's compliance with the Standards of Conduct, Code of Conduct, market-based rate tariff, and MISO's OATT requirements. Selective tests included those necessary to verify the accuracy of required informational postings on LG&E's OASIS, the effectiveness of written procedures and internal controls related to the Standards of Conduct, and compliance with all the provisions of the Standards of Conduct, LG&E's Code of Conduct, LG&E's market-based rate tariff, and the MISO OATT.

Additionally, we reviewed physical and electronic security over transmission operations and information. We discussed with LG&E personnel matters related to the corporate structure, Energy and Marketing Affiliates, local and wide area networks, shared functions, and the Standards of Conduct training received. We reviewed e-mail records and recorded conversations between LG&E's transmission operations and its Energy and Marketing Affiliates.

---

[7] *Louisville Gas & Elec. Co.*, 85 FERC ¶ 61,125 (1998) (accepting for filing joint market-based rate tariff of LG&E and KU, FERC Electric Tariff, Original Volume No. 2); *LG&E Operating Cos.* Docket No. ER99-1623-000. Letter Order, Jun. 4, 1999 (accepting revised tariff sheets to Original Volume No. 2 permitting limited sales to certain affiliates); *Louisville Gas & Elec. Co.*, Letter Order, Docket No. ER02-1077-000, Apr. 16, 2002 (accepting "short form" market-based rate tariff as Original Volume No.3).

[8] *Midwest Independent Transmission System Operator, Inc., et al.*, 84 FERC ¶ 61,231 (1998); *order on reconsideration*, 85 FERC ¶ 61,250 (1998); *order on reh'g*, 85 FERC ¶ 61,372 (1998); *order on compliance filing*, 87 FERC ¶ 61,085 (1999).

III. CODE OF CONDUCT FINDINGS AND RECOMMENDATIONS

1. Functional, Physical and Operational Separation of LG&E's WMF and Affiliated Power Marketer

LG&E's WMF and its principal affiliated power marketer (LEM) were not functionally, physically and operationally separate to the maximum extent practical, as required by LG&E's Code of Conduct. The WMF and LEM were functionally within the same LG&E business unit, and reported to the same company officer; the WMF and LEM shared physical facilities without strong controls to prevent information sharing; and the WMF and LEM shared a telephone recording system that provided LEM employees access to operational information such as WMF trading activities.

Pertinent Guidance

Section 3 of LG&E's Code of Conduct states that "(t)o the maximum extent practical, employees of the Utilities [*i.e.*, LG&E's WMF] who operate the Utilities' systems or engage in power purchasing or selling on behalf of the Utilities will be physically, operationally, and functionally separate from employees of the Marketers performing power marketing activities."[9]

Discussion

Collectively, the lack of functional, physical, and operational separation between WMF and LEM precluded LG&E from operating these entities as separate business units to the maximum extent practical as required in Section 3 of LG&E's Code of Conduct.

Functional Separation Between WMF and LEM

LG&E's WMF and its primary affiliated power marketer (LEM) were not functionally separate to the maximum extent practical since they functionally reported to the same company officer, *i.e.*, the Senior Vice President (SVP) of Energy Marketing. The employees of the two trading operations attended periodic meetings together, convened by the SVP of Energy Marketing. As described in the compliance finding "Sharing of Market Information" which follows next in this Audit Report, general market

[9] *LG&E Power Mktg., Inc.*, 68 FERC ¶ 61,247 (1994); *modified on other grounds*, 69 FERC ¶ 61,153 (1994). LG&E Power Mktg.'s name was changed to LG&E Energy Marketing Inc. (LEM). *See* Notice of Name Change, Docket No. ER97-3418-000 (filed June 24, 1997).

information, as well as specific market information about WMF and LEM trading operations was discussed at these meetings.

According to the job description of the SVP Energy Marketing, the occupant of the position was responsible for establishing the strategic direction and management of the energy marketing, fuel procurement and trading activities for the WMF and also directs the optimization of the corporation's energy-related integrated gross margin. This job description indicates that the SVP Energy Marketing is expected to coordinate WMF and LEM activities to provide a greater return for the LG&E corporate family. This lack of functional separation between WMF and LEM was inconsistent with LG&E's Code of Conduct.

Physical Separation Between WMF and LEM

LG&E lacked sufficient physical barriers to ensure that the WMF's non-public market information was not shared with LEM. WMF operations and LEM operations were both located on the seventh floor of LG&E's headquarters building. Sharing a floor is not a violation of the Code of Conduct, as long as there are sufficient controls to ensure the physical separation of employees and operations. The physical space occupied by WMF operations were secured by a card key access system. However, LEM's operations were not secured by a card key access system, and the workspace of LEM employees (with the exception of the Director of LEM) was arranged in open carrels. WMF employees passed by LEM's workspace on their way to and from a conference room shared by the two trading operations, and the employees shared common facilities such as kitchen and restrooms. WMF and LEM employees frequently held discussions on the LEM trading floor, but LG&E asserted and the employees we interviewed confirmed that the information exchanged between WMF and LEM traders was not prohibited information—it was limited to public information regarding the market and market information about LEM.

The seventh floor also contained LG&E's risk management and energy accounting functions, both of which have access to WMF information. The risk management and energy accounting offices were not protected, e.g., through card key access, against entry by LEM personnel.

Operational Separation with Respect to Recorded Phone Calls

LG&E recorded phone calls of its traders and dispatchers for both the WMF and LEM functions on two RACAL digital tape recorder machines. Each machine recorded calls made by employees of both organizations on digital tapes. Each digital tape contained approximately 60,000 to 75,000 calls or about 21-28 days worth of recorded calls containing conversations made by both WMF employees and LEM employees.

Each call was identified by date, time, and channel number which corresponded to a person or workstation. A recorded call varied in length from a few seconds to several minutes.

The two RACAL recorder machines and tapes were located on the seventh floor of LG&E's headquarters building in a locked room with access controlled by a LEM administrative employee. The LEM administrative employee provided access to specific tapes when WMF or LEM employees requested access to the tapes. The LEM administrative employee initially set up the machine to a channel, date and time, then instructed the WMF and LEM employees how to operate the machine to find other calls. The listening process involved searching and listening to the tape on a trial and error basis until the call was identified. The LEM administrative person did not remain in the room at all times while the WMF or LEM employees listened to the tapes, and these employees had the opportunity to access the entire contents of a tape containing both WMF and LEM recordings.

Recommendations

We recommend that LG&E:

1. Take all appropriate actions necessary to ensure that WMF employees and LEM employees are functionally and physically separate to the maximum extent practical, as required under LG&E's Code of Conduct.

2. Implement procedures to ensure that authorized access to the tape recordings are properly documented.

3. Implement procedures to separate tape recordings for WMF and LEM channels.

4. Implement controls to provide access to only one tape recording machine when WMF or LEM personnel are authorized to listen to tapes and implement controls to prevent unauthorized access to channels of historical tapes which contain recorded conversations of both WMF and LEM channels.

5. LG&E shall submit all procedures and controls to OE for approval within 30 days of issuance of a Final Audit Report in this docket.

Actions Already Taken by LG&E

After we discussed our concerns with the lack of physical separation between LEM and WMF, LEM physically moved from the seventh floor to the fourth floor of the LG&E building and LEM employees no longer have access to the seventh floor as of March 31, 2006.

LG&E also began maintaining a written log of all access to tapes and revamped its recording system so that now WMF and LEM employee conversations are recorded on separate tapes and machines. We verified that this change had been made during our site visit in October 2005. However, LG&E must still implement access controls to the tapes when WMF or LEM employees listen to tapes containing recorded conversations of both WMF and LEM channels. Also, LG&E must implement physical access controls to the recording machines if WMF or LEM employees are provided access to the secure room to listen to tapes.

The corrective actions do not solve the functional separation problem between WMF and LEM. LG&E will submit a plan to functionally separate WMF and LEM.

2. Sharing of Market Information

LG&E's WMF shared market information with LEM through presentations at joint staff meetings, in violation of LG&E's Code of Conduct. Also, password access controls to the shared Energy Management System (EMS) were insufficient and inconsistent with LG&E's password security policy.

Pertinent Guidance

Section 4 of LG&E's Code of Conduct states that "(n)o employee of the Utilities will share market information with any employee of the Marketers unless all such information is simultaneously made available to the public. The policy will not apply to market information known to be publicly available, or to market information disclosed to employees of the Marketers or the Utilities who are engaged in support functions, including human resources, information resources, data processing, finance, legal, accounting and other support personnel who do not participate in directing, organizing and executing the day-to-day business decisions of the wholesale merchant or generation functions of the Utilities or the Marketers, *provided* that such employees are prohibited from acting as conduits to pass market information obtained from the Utilities to the Marketers."[10] (emphasis in original.)

LG&E's password security policy requires a password for each employee accessing LG&E's Local Area Networks (LAN) and Wide Area Networks (WAN).

Discussion

Joint Staff Meetings Between WMF and LEM

LG&E's WMF shared non-public market information with LEM through presentations at joint staff meetings, in violation of LG&E's Code of Conduct. The monthly trading meetings normally took place during the last week of each calendar month. In addition to the SVP of Energy Marketing, the managers of WMF and LEM attended, as well as staff from WMF and LEM, plus staff from the Market Analysis, Trading Controls, Operations Analysis and Fuels Management sections.

During the months of August, 2004 through May, 2005, the agendas of the Trading Meetings remained unchanged. The first item on the agenda was a presentation by the Manager of the WMF on the results of Regulated Off-System Sales (OSS) for the month, and how the results compared with the amount budgeted for that item. This

---

[10] *Id.*

information included reforecast graphs for the calendar year-to-date, the results for the current month-to-date, the factors leading to the results (including such items as purchase power costs and transmission expenses), and a review of the profit-at-risk graph. Following this presentation by the WMF, LEM presented a report on its sales operations for the previous month and its forecasts and plans for the future.[11] Following LEM's presentation, the SVP of Energy Marketing dismissed the LEM employees from the meeting after which the WMF made additional reports about its operations and forecasts.

LG&E's Code of Conduct states that no employee of the WMF will share market information with any affiliated power marketer employee unless all such information is simultaneously made available to the public. Based on review of the agendas, and interviews with WMF personnel, we concluded that the WMF Off-System Sales' information presented at the beginning of the monthly meetings by the Manager of the WMF was WMF market information. This information was disclosed to LEM personnel present at the beginning of these meetings, a violation of LG&E's Code of Conduct.

Password Access to EMS Information

LG&E's WMF and LEM both use a shared EMS, partitioned into WMF generation data, LEM generation data, and LG&E transmission data. Password access controls to the shared EMS were insufficient and inconsistent with LG&E's password security policy. Prior to February 2004, LG&E permitted WMF and LEM users to access the EMS using separate group accounts and passwords, rather than using unique user accounts and passwords. The failure to require unique password access was contrary to LG&E's password security policy and increased the risk of inappropriate information access via the EMS. Specifically, group passwords are easier to disseminate and it is not possible to track the identity of individuals that use a group account to ensure that only those with appropriate clearance have accessed the EMS. Because WMF employees and LEM employees used group accounts and passwords, it was not possible to track individual access to specific account information.

[11] The information related to Western Kentucky Electric (WKE), LEM's sole remaining customer. In past years the information also related to LEM's contract with Oglethorpe Power Corporation (OPC).

Recommendations

We recommend that LG&E:

6. Create controls consistent with LG&E's Code of Conduct to ensure that there is no exchange of market information stemming from joint trading meetings for WMF and affiliated power marketing personnel.

7. Conduct an independent review by the internal audit department or an outside auditing firm when the new EMS is implemented in 2006 to ensure that there is no improper or unauthorized EMS screen access.

8. LG&E shall submit all controls to OE for approval within 30 days of issuance of a Final Audit Report in this docket. Also, LG&E shall submit the results of the independent review of the EMS to OE within 30 days after implementing its new EMS or issuance of a Final Audit Report in this docket, whichever is later.

Actions Already Taken by LG&E

After we discussed our concerns with LG&E about joint trading meetings between WMF and LEM, LG&E changed the agenda of the monthly trading meetings starting in June 2005. The agenda was altered so that the presentation about WMF's OSS is not made until later in the meeting, after LEM employees have left the meeting. In addition, beginning in December 2005, LG&E adopted certain process changes, including the requirement that the CCO or his designee attend all joint WMF and LEM meetings, and maintain a high-level agenda and/or minutes of each meeting.

LG&E implemented unique user accounts and passwords for its current GE/Harris EMS in February 2004. LG&E is currently developing, installing and testing a new EMS that should be operational in 2006.

3. Posting of Information on Sales to Affiliates at Market-Based Rates

LG&E's EBB was inaccessible to non-affiliated market participants, and the information on the EBB was not consistent with Commission requirements. The EBB would have been difficult for non-affiliate market participants to find, given that for some period of time it was located on a website of an LG&E affiliate that was not a party to affiliate sales. In addition, for some period of time it may not have been accessible over the internet. Moreover, the information and timing on offers to sell and actual sales to affiliates were not consistent with the specific requirements in LG&E's Code of Conduct.

Pertinent Guidance

On January 29, 1999, LG&E petitioned the Commission for blanket authority to authorize the Utilities, *i.e.*, LG&E's WMF, to sell energy at market-based rates to their power marketing affiliates. Acknowledging the Commission's concern about protecting captive ratepayers from subsidizing affiliate marketing operations, LG&E committed to adopt the safeguards the Commission approved in Detroit Edison Company.[12]

To implement these safeguards, LG&E amended its Code of Conduct to add the following requirements: "The Utilities will sell power to the Marketers at a rate that is no lower than the rate the Utilities charge to nonaffiliates; simultaneously with making an offer to sell power to the Marketers, the Utilities will make the same offer to nonaffiliates through a posting on their electronic bulletin board ("EBB"); and simultaneously with the striking of a power sales transaction with the Marketers, the Utilities will post the actual price paid on their EBB."[13]

Discussion

Accessibility of EBB Information to Market Participants

We sought to create a timeline for LG&E's EBB. LG&E's WMF made energy sales at market-based rates to LEM from 1999 through the Spring of 2005, but we could not confirm that the information posted on such sales was accessible to market participants. Based on the documentation provided to us by LG&E:

- From 1999 through December 2003, the sales information was posted on an EBB website for LG&E Power, one of LG&E's affiliated power marketers.

---

[12] 80 FERC ¶ 61,348 (1997).

[13] Docket No. ER99-1623-000, Compliance Filing of Louisville Gas and Electric Company and Kentucky Utilities Company, filed March 4, 1999, at 2.

- In December 2003, the EBB containing the sales information migrated from the LG&E Power website to the LG&E Energy website.

- In April 2005, LG&E provided us the website address for the EBB, http://apps.lgeenergy.com/fercgen/gensales.asp. When we tried to access the EBB at this address, the page would not display. We subsequently asked LG&E how to access the EBB. On May 4, 2005, the internet address on LG&E Energy's website worked. We asked LG&E when this link to the EBB was made operational; LG&E informed us that it was made operational on May 1, 2005.

LG&E stated that other than LG&E's filing made in 1999 revising its Code of Conduct to post affiliate transactions on an EBB, it could not recall any occasions where it publicized the existence of the EBB. LG&E, however, could not recall a single instance when a market participant had inquired about any posting on the EBB.

Posted Offers to Sell on the EBB

LG&E's Code of Conduct required LG&E to make a simultaneous offer on the EBB to sell to non-affiliates the same product it was offering to sell to its affiliate. We concluded that the posting of offers to sell on the EBB were not consistent with the requirements of LG&E's Code of Conduct.

We reviewed archived EBB data for the audit period. Typically, each month on the first of the month, LG&E's WMF would post on the EBB an offer to sell a block of energy on an hourly basis. This monthly posting was at an asking price of $12/MWh for virtually every month that a monthly offer was posted. LG&E stated that the asking price was set at $12/MWh in order to induce counterparties to enter negotiations to purchase from LG&E's WMF.

We reviewed LG&E's variable costs on a generator-by-generator basis. Although prices of coal and other inputs changed over the course of the period that LG&E posted offers on the EBB, we concluded that had LG&E sold energy at $12/MWh during any hour during which it posted an asking price of $12/MWh, it would have been selling energy at a price less than its incremental cost. Moreover, our review of the EBB shows that WMF never sold energy to LEM at a price of $12/MWh or less. LG&E's strategy of posting an asking price of $12/MWh did not satisfy the Code of Conduct requirements to simultaneously offer hourly energy to non-affiliated market participants at the same price that it would offer such energy to its affiliate.

Prices of Affiliate Sales

We evaluated whether the prices at which WMF sold energy to LEM were consistent with the requirements of LG&E's Code of Conduct, *i.e.*, at a rate that is no lower than the rate that WMF sold to non-affiliated buyers. LG&E had no written procedures or other controls for its WMF traders to follow to determine an appropriate market price at which the WMF would sell to LEM. LG&E's WMF traders established the market price through telephone queries and broker quotes prior to negotiating a next-hour energy sale to LEM. We listened to recorded phone calls during hours in which WMF traders sold energy to LEM. We found no evidence that WMF traders sold energy to LEM at prices less than the market price in accordance with LG&E's Code of Conduct. However, when we reviewed the recorded phone calls, we found that WMF traders did not generally employ strong controls to establish the market price.

EBB Postings in 2001

We had specific concerns whether LG&E was properly using the EBB to post offers and sales from WMF to LEM to support a long-term sales obligation LEM had with Morgan Stanley, specifically affiliate sales in 2001. Based on the data provided to us by LG&E, we found the following EBB posting errors:

- WMF sold to LEM 50 MWh of energy during each off-peak hour during the month of May 2001 without posting offers or transactions on the EBB. We estimated these energy sales in May 2001 to total nearly 20,000 MWh, and to have generated revenues of approximately $500,000.

- LG&E failed to post on the EBB offers or transactions when WMF sold energy to LEM to support LEM's sales to Morgan Stanley for an additional 10 days during calendar year 2001.

Recommendations

We recommend that LG&E:

9. Develop written procedures regarding the use of its EBB. Specifically, the written procedures should address how LG&E will ensure that the price at which it sells energy to its affiliate is no lower than the price at which it sells to non-affiliates, and how LG&E will post offers and sales on the EBB to make the information available to other market participants to demonstrate that its affiliate sales are at non-preferential prices.

10. Develop a plan to ensure that the EBB is fully accessible, and that market participants know where to find the EBB on the LG&E website.

11. LG&E shall submit all procedures and plans to OE for approval within 30 days of issuance of a Final Audit Report in this docket.

Actions Already Taken by LG&E

We had numerous discussions with LG&E about the accessibility and effectiveness of its EBB postings. As of January 2006, LG&E had a link from its corporate website to the EBB. In addition, LG&E presented us plans for making the information posted on the EBB consistent with LG&E's Code of Conduct. LG&E has agreed to finalize these plans and to develop written procedures to guide trading staff on the use of the EBB within 30 days of the issuance of a Final Audit Report in this docket.

IV. STANDARDS OF CONDUCT FINDINGS AND RECOMMENDATIONS

4. Disclosures of Transmission and Customer Information

LG&E transmission employees improperly disclosed transmission and customer information to employees of its WMF that was not contemporaneously available to the public, and failed to post the information disclosure on OASIS.

Pertinent Guidance[14]

A Transmission Provider must ensure that any employee of the Marketing or Energy Affiliate is prohibited from obtaining information about the Transmission Provider's transmission system through access to information not posted on the OASIS or Internet website or that is not otherwise also available to the general public without restriction.[15]

An employee of the Transmission Provider may not disclose to its Marketing or Energy Affiliates any information concerning the transmission system of the Transmission Provider or the transmission system of another through non-public communications conducted off the OASIS or Internet website, through access to information not posted on the OASIS or Internet website that is not contemporaneously available to the public, or through information on the OASIS or Internet website that is not at the same time publicly available.[16]

A Transmission Provider may not share any information, acquired from non-affiliated transmission customers or potential non-affiliated transmission customers, or developed in the course of responding to requests for transmission or ancillary service on the OASIS or Internet website, with employees of its Marketing or Energy Affiliates,

[14] Some of the incidents supporting this finding occurred under the former Order No. 889 Standards of Conduct requirements, *i.e.*, Part 37 requirements pre-September 22, 2004, Part 358 requirements thereafter. There are no significant differences in the specific requirements of Part 37 and Part 358 that bear upon the finding that LG&E improperly disclosed transmission and customer load information.

[15] 18 C.F.R. § 358.5(a)(2) (2005).

[16] 18 C.F.R. § 358.5(b)(1) (2005).

except to the limited extent information is required to be posted on the OASIS or Internet website in response to a request for transmission service or ancillary services.[17]

If an employee of the Transmission Provider discloses information in a manner contrary to the requirements of sections 358.5(b)(1) and (2), the Transmission Provider must immediately post such information on the OASIS or Internet Web site.[18]

Also, LG&E's posted implementation procedures provided that "any person with knowledge or concerns regarding activities that may have resulted, or could result, in a violation of the Standards of Conduct and/or Standards of Conduct Written Procedures is strongly encouraged, expected, and required to report them to the CCO without delay."

Discussion

Disclosures of Transmission Information by Telephone

On at least three occasions, once in May, 2004 and twice in November, 2004 LG&E transmission employees disclosed transmission line loading and operating status information to LG&E generation dispatchers during the course of generation re-dispatch events. LG&E's generation dispatch function is organizationally and functionally within its marketing business unit; therefore generation dispatch personnel are Energy and Marketing Affiliate employees.[19] In each instance, the transmission information was disclosed through non-public communication.

LG&E identified three calls involving the disclosure of non-public transmission information relating to the loading of, line operational status, or redispatch or switching relief options for the 345 kV line Smith – Hardin County; 138 kV line Paddys Run – Paddys West; and 138 kV line Cane Run 6 – Cane Run Switching. LG&E acknowledged that the disclosed transmission information was not otherwise available to market participants through OASIS or other sources at the time that it was disclosed. We

[17] 18 C.F.R. § 358.5(b)(2) (2005).

[18] 18 C.F.R. § 358.5(b)(3) (2005).

[19] The manager of generation dispatch reports to the Director of Trading who reports to the Senior Vice President for Energy Marketing. The generation dispatch desk is on the trading floor, located next to the workstation used by LG&E's real-time traders. Moreover, on occasion, LG&E's generation dispatchers talked to potential energy buyers and sellers on the phone and made trades if no one else on the trading floor was available to do so.

reviewed the disclosed information and determined that its disclosure to generation dispatch personnel was not necessary to ensure reliability and hence is not exempt under 18 C.F.R. § 358.5(b)(6) (2005). LG&E confirmed that the transmission information disclosed was not shared with traders, and there were no trades made by generation dispatchers in the hours subsequent to the disclosure of transmission information.

LG&E's generation dispatchers received Standards of Conduct training, and had available to them LG&E's Standards of Conduct implementation procedures, which required that improper disclosures of non-public transmission information be reported to the CCO. The generation dispatch employee did not disclose the incidents to anyone, including the CCO, so the disclosures were not posted on LG&E's OASIS after they occurred.

Disclosure of Transmission Information at a Meeting Attended by Transmission and Marketing Employees

During the audit period, we identified one meeting in which transmission personnel and marketing personnel were present at which LG&E transmission personnel disclosed non-public information regarding the status of two transmission projects. LG&E did not subsequently post the disclosures on its OASIS. At a Long Term Planning meeting that the SVP of Energy Marketing attended, the Director of Transmission discussed two transmission projects, providing information that was not publicly available in the Midwest ISO Transmission Expansion Plans ("MTEP"). These Projects were a 138/69kV transformer at VA City – Clinch River, which was a new interconnection tie-line between LG&E and American Electric Power Company, Inc., and a 138/69kV transformer at Paris substation, which was a reinforcement of the existing tie-line between LG&E and East Kentucky Power Cooperative. Each of the above two proposed projects would increase the transmission capacity between LG&E and the adjacent control area. LG&E did not post in a timely manner the disclosure on the OASIS after it occurred. We found no evidence that LG&E's Energy or Marketing Affiliates traded on this information.

Disclosure of Customer Load Data by E-Mail

On the first of the month, on a monthly basis through February 2005, a transmission employee e-mailed a marketing employee specific, non-public customer load information and failed to post in a timely manner the disclosures on OASIS.[20] Prior

[20] In *Allegheny Power Service Corporation et al, (Allegheny)* the Commission stated that the WMF may have access to control area load and not the specific load of third-party transmission customers within the same control area. *See Allegheny,* 84 FERC ¶ 61,131 at 61,729 (1998).

to August 1, 2003, the e-mails identified the date, time and LG&E's control area peak load, and load for the same date and time for LG&E, Hoosier Energy, Owensboro Municipal Utilities, Tennessee Valley Authority, and East Kentucky Power Cooperative. Beginning August 1, 2003 and continuing through February 1, 2005, the e-mails added the customer's monthly energy usage, peak load and load factor.[21] LG&E acknowledged that this information was not publicly available. Knowledge of specific third-party load information could have been used to the advantage of LG&E's traders, although we found no evidence that this occurred.

Recommendations

We recommend that LG&E:

12. Post OASIS notices for all of the disclosures of non-public transmission information by LG&E's transmission function employees identified in this Audit Report. These postings should include the date, time, type of information disclosed, and other pertinent information.

13. Create and implement controls to prevent prospectively the disclosure of non-public transmission information to marketing employees performing generation dispatch functions and controls to ensure that any subsequent disclosure(s) are posted on OASIS consistent with Commission regulations. Such controls need to emphasize LG&E's policy that all concerns related to the Standards of Conduct should be brought to the attention of the CCO.

14. Create and implement controls to prevent prospectively the disclosure of non-public transmission information during meetings attended by both transmission and marketing employees, and controls to ensure that any subsequent disclosure(s) are posted on OASIS consistent with Commission regulations. Such controls need to emphasize LG&E's policy that all concerns related to the Standards of Conduct should be brought to the attention of the CCO.

15. Perform a review of all transmission and customer information shared through e-mail distribution in order to ensure that such information is not inappropriately shared with LG&E's Marketing and Energy Affiliate employees.

[21] The load factor represents the ratio of the average load over a designated period of time to the peak load occurring during that period.

16. LG&E shall submit all controls and the results of its email distribution review to OE for approval within 30 days of issuance of a Final Audit Report in this docket.

Actions Already Taken by LG&E

We discussed our concerns about the disclosure of transmission and customer information. LG&E informed us that it is developing process changes for addressing our concerns on a prospective basis, and that ultimately the process changes would be converted into formal written policies within 30 days of issuance of a Final Audit Report in this docket.

5. Standards of Conduct Training

LG&E's Standards of Conduct training program was inconsistent with Commission regulations and LG&E's own training implementation plans—more than one year after the effective date of Order No. 2004 (*i.e.*, 9/22/04), LG&E had failed to provide Standards of Conduct training for several hundred of the employees LG&E was required to train.

Pertinent Guidance

Order No. 2004 codified the training requirement as follows: "Transmission Providers shall train officers and directors as well as employees with access to transmission information or information concerning gas or electric purchases, sales, or marketing functions. The Transmission Provider shall require each employee to sign a document or certify electronically signifying that s/he has participated in the training." [22] Moreover, training was to be completed by the implementation date of Order No. 2004: "Each Transmission Provider must be in full compliance with the standards of conduct by September 22, 2004."[23]

Order No. 2004 required a Transmission Provider to post its implementation procedures on its OASIS or website, specifically requiring that Transmission Providers "must explain...whether employees have been offered training on the standards of conduct, and whether employees are required to read and sign acknowledgement forms."[24] LG&E's posted implementation procedures have limited detail on its training program. LG&E directed us to an internal company training plan, which states (in part):

- All affected Company Personnel as well as employees of Energy and Marketing Affiliates (*i.e.*... except clerical, maintenance and field personnel) shall receive *Standards of Conduct* training prior to the September 22, 2004 implementation date.

- The initial *Standards of Conduct* training shall be conducted through interactive training programs developed and prepared by the Edison Electric Institute.[25]

---

[22] 18 C.F.R. § 358.4(e)(5) (2005).

[23] 18 C.F.R. § 358.4(e)(2) (2005).

[24] FERC Stats. & Regs, Regulations Preambles ¶ 31,155 at P 136.

[25] "FERC Standards of Conduct, Order Nos. 2004, 2004-A, 2004-B, Training plan, August 19, 2004, Overview."

Discussion

We reviewed LG&E's training program and compared it to the requirements in Order No. 2004, as well as LG&E's training plan. We concluded that LG&E did not provide training to all employees requiring training. As of November 2005, more than one year after the September 22, 2004 implementation date of Order No. 2004, LG&E had not provided training to all employees that fall under the definition of employees who needed to be trained, *i.e.*, "employees with access to transmission information or information concerning gas or electric purchases, sales, or marketing functions."[26]

We could not determine the exact number of employees that required, but had not received, training. Employees that required Standards of Conduct training but did not receive training included:

- A handful of employees of the service company, *e.g.*, in business units such as Audit Services and Legal;
- Approximately 100 shared service employees, in business units such as Planning & Control;
- As many as 2,000 employees at LG&E-owned transmission and generation facilities, who had no training other than notification that new Standards of Conduct were in effect.[27]

We discussed with LG&E the need to determine whether the employees in these business units have access to information concerning gas or electric purchases, sales or marketing functions that would trigger a training requirement under 18 C.F.R. § 358.4(e)(5) (2005), and when they do, to ensure that they have Standards of Conduct

[26] 18 C.F.R. § 358.4(e)(5) (2005).

[27] LG&E designated these employees as field and maintenance personnel and as such did not provide training to them. But the training requirement in Order No. 2004 does not hinge on whether employees are designated as field and maintenance personnel, but rather whether an employee has access to non-public transmission information or information concerning gas or electric purchases, sales or marketing functions. LG&E told us it did not make this determination with respect to its field and maintenance personnel. As such, we could not determine how many of these employees should have received training. LG&E did not assert that these employees did not have access to non-public transmission information or information concerning gas or electric purchases, sales or marketing functions.

training. LG&E agreed to review its training program, specifically to identify the additional employees that should have received training.

Recommendations

We recommend that LG&E:

17. Strengthen the implementation of its training program to ensure that on a going-forward basis, its training program is consistent with Commission requirements and its internal training plans.

18. Develop written procedures to ensure that new employees, and transferring employees that require training, receive training.

19. Conduct a review to ensure that all of the employees that have "access to transmission information or information concerning gas or electric purchases, sales, or marketing functions..." are scheduled for training, have received training, and are certified.

20. LG&E shall submit all changes to the implementation of its training program and procedures developed to OE for approval within 30 days of issuance of a Final Audit Report in this docket. Also, LG&E shall submit the results of its review of employee access to information within 30 days after issuance of a Final Audit Report in this docket.

Actions Already Taken by LG&E

We discussed LG&E's training program with the CCO, and other LG&E officials. On November 10, 2005, LG&E submitted a letter to us outlining an enhanced training program. We reviewed LG&E's plan and found it to be consistent with the requirements of Order No. 2004, the audit findings, and our recommended remedies.

LG&E proposed to require training for all LG&E employees who fall within the definition in 18 C.F.R. § 358.4(e)(5) (2005). LG&E proposed to use the EEI computer-based Training Program, including the certification of training completion. For employees without internet access, a paper version of the training program will be used for the training. LG&E informed us on January 11, 2006, that as of that date, it had increased the number of LG&E employees who had received training by 80%, from approximately 600 employees to approximately 1100 employees.

6. Controls Used to Limit Access to System Control Centers

LG&E did not follow its posted implementation procedures to control and track access of its marketing employees to LG&E's two system control centers, including the requirement that LG&E marketing employees obtain permission from the CCO before visiting the system control centers.

Pertinent Guidance

Order No. 2004 requires that a Transmission Provider's employees engaged in transmission system operations "must function independent from employees of its Marketing and Energy Affiliates."[28] Specifically, a Transmission Provider is prohibited from permitting the employees of its Marketing or Energy Affiliates from "having access to the system control center or similar facilities used for transmission operations or reliability functions that differs in any way from the access available to other transmission customers."[29]

LG&E's posted implementation procedures provide that LG&E marketing employees must obtain permission from the CCO before visiting the system control centers: "The Chief Compliance Officer shall maintain a written record of each such decision for inspection upon request by the Commission."[30]

LG&E's posted implementation procedures also prescribe access control to the system control centers.

> The Companies shall maintain a written log book at each Transmission System Operating Center for purposes of documenting the instances in which a transmission customer, whether an employee(s) of an Energy and/or Marketing Affiliate or a representative(s) of an unaffiliated third-party, visited these facilities. The written log book should contain the: (1) name of the transmission customer; (2) the date and time of the visit; and (3) the Transmission Function Employee(s)

---

[28] 18 C.F.R. § 358.2(a) (2005).

[29] 18 C.F.R. § 358.4(a)(3)(ii) (2005).

[30] "Joint Written Procedures Implementing Standards of Conduct for Transmission Providers as Adopted by the Federal Energy Regulatory Commission in Order No. 2004, Effective September 22, 2004" Section IV.A.2.b.

or other Company Personnel hosting the transmission customer; (4) whether the transmission customer is an affiliate; and (5) purpose for the visit.[31]

Discussion

LG&E operates two separate system control centers. One control center, called Waterside, is located in Louisville, KY, in a building approximately two blocks from the LG&E corporate headquarters. The other control center, called Dix Dam, is located in Burgin, KY, at the site of the Dix Dam generating facility.

LG&E used card key access to restrict direct access to its system control centers. However, we found a number of problems with the controls employed to track access of visitors (including LG&E marketing employees) to LG&E's system control centers.

CCO Permission to Visit the System Control Centers

LG&E's posted implementation procedures provide that LG&E marketing employees should submit a written request to the CCO prior to visiting either one of the system control centers. Based on our review of the Waterside log sheets, on at least five occasions, two LG&E employees with marketing or marketing-related responsibilities visited the Waterside facility after September 22, 2004.[32] The CCO told us that there was no record that marketing employees had sought permission to enter the control centers, and no record of CCO approval of such requests.

Controls on Visitors Entering the System Control Centers

The written log books controlling visitors to the system control centers were inconsistent with LG&E's posted implementation procedures. The logs did not collect some pertinent information that LG&E's implementation procedures required. Many of the entries on the log sheets were unintelligible to us, and some of these entries were unintelligible to LG&E personnel as well. As a result, we could not determine the full extent to which LG&E marketing employees (and non-affiliated transmission customers) had access to the system control centers and could not determine whether LG&E

[31] *Id.*

[32] One of the employees was the manager of the generation dispatch function, which staff established was part of the marketing function. The other was the manager of market policy—the position description for this individual said his department was responsible for monitoring and analyzing emerging electric markets and educating Energy Marketing staff on the implications of new market operations.

marketing employees had access in any way that differed from the access provided to non-affiliated transmission customers.

Access to Transmission Information Once Inside the System Control Centers

At both the Waterside and Dix facilities, a visitor standing at the door to the control centers had a line of sight into the control room, and was able to see transmission status information. This concern is heightened because of the relatively large number of LG&E marketing employees that visited a system control center. For example, our review of log sheets indicated that in the two year period prior to implementation of Order No. 2004, LG&E marketing employees may have made as many as 50 separate visits to the Waterside facility.

Recommendations

We recommend that LG&E:

21. Review and strengthen its system control center access procedures to ensure that its control procedures: (a) adhere to its own posted implementation procedures as it relates to CCO permission to visit control centers and maintenance of log books; (b) are followed by LG&E employees including the CCO and CCO designees; and (c) are certified in compliance with Order No. 2004 and LG&E's posted implementation procedures. LG&E shall submit all procedures to OE for approval within 30 days of issuance of a Final Audit Report in this docket.

22. Ensure that the entrances into the Waterside control room and Dix Dam control room are such that a visitor that enters the Waterside and Dix Dam facilities does not have a line of sight into the control rooms or to any workstations displaying data on transmission status.

Actions Already Taken by LG&E

LG&E informed us that on January 10, 2006, it revised its website to notify LG&E marketing employees that require access to the system control centers to seek written permission before each visit from the CCO. In addition, LG&E indicated that no later than January 13, 2006, the log books would be updated to conform to LG&E's posted implementation procedures, and temporary covers would be installed on all windows and doors that allow a line of sight into the system control centers.

7. Organizational Charts

LG&E's posted corporate and functional organizational charts (as of April 2005) failed to include or accurately show: detailed organizational charts for business units engaged in the sales function; the position of its Marketing and Energy Affiliates within the corporate structure; and sufficient detail to indicate that LG&E's service company is the employment mechanism for the Marketing and Energy Affiliates and the Transmission Provider.

Pertinent Guidance

The Order No. 2004 requirements for posting organizational charts provide that:

(3) A Transmission Provider must post comprehensive organizational charts showing:

(i) The organizational structure of the parent corporation with the relative position in the corporate structure of the Transmission Provider, Marketing and Energy Affiliates;

(ii) For the Transmission Provider, the business units, job titles and descriptions, and chain of command for all positions, including officers and directors, with the exception of clerical, maintenance, and field positions. The job titles and descriptions must include the employee's title, the employee's duties, whether the employee is involved in transmission or sales, and the name of the supervisory employees who manage non-clerical employees involved in transmission or sales.

Further, Order Nos. 2004-A and 2004-B requires:

If a corporation uses a service company as the employment mechanism for the Transmission Provider and its Marketing or Energy Affiliates, the organizational charts should clearly specify those circumstances. Similarly, if a corporation uses both functional and structural organizational charts for its management, the organizational charts must accurately reflect its operations....[33]

With respect to whether a detailed organizational chart is also required for a service company, the answer depends on the functions that the service company is

[33] FERC Stats. & Regs, Regulations Preambles ¶ 31,161 at P 163.

performing. If the service company is performing transmission functions, additional detail is required.[34]

Discussion

LG&E's posted several organizational charts on its website at http://lgeenergy.com/regulatory/soc.asp[35] which showed a high-level organizational structure, including the holding company which owns LG&E Energy LLC, and the legal entities under LG&E Energy LLC, including notably: the operating companies (Kentucky Utilities Company and Louisville Gas and Electric Company); the service company (LG&E Energy Services, Inc.); and an LG&E marketing affiliate (LG&E Energy Marketing Inc., or LEM).

Additional posted organizational charts showed some —but not all— of the business units of the service company. The organizational charts showed a Senior Vice President (SVP) for Energy Services, with the following direct reports: Director of Transmission; SVP for Energy Marketing; VP for Regulated Generation; and VP Power Operations for Western Kentucky Energy.

However, the only business unit for which detailed organizational charts, job titles, chains of command, and job descriptions were posted was the Director of Transmission. Such detailed information was not posted for the sales functions, *i.e.*, the SVP for Energy Marketing, VP for Regulated Generation, and VP Power Operations for Western Kentucky Energy. The sales functions under the SVP for Energy Marketing included the following business units: Director of Trading; Director of Market Analysis & Valuation; Director of Non-Utility Marketing; Manager of Operations Analysis and System Implementation; Director of Corporate Fuels & By-Products; and Director of Business Information.

In addition, the posted organizational charts did not show the relative position in the corporate structure of all of LG&E's Marketing and Energy affiliates and did not clearly indicate that LG&E's service company is the employment mechanism for its Marketing and Energy Affiliates and Transmission Provider. For example:

- LG&E's postings showed one of LG&E's Marketing and Energy Affiliates, *i.e.*, LG&E Energy Marketing Inc. (LEM), as a separate corporate entity, but did not clearly indicate that LEM employees are in the service company along with transmission function employees; and

[34] FERC Stats. & Regs, Regulations Preambles ¶ 31,166 at P 79.

[35] We reviewed the organization charts on April 5, 2005.

- LG&E's postings failed to show what position another Marketing and Energy Affiliate, LG&E Power Services LLC, occupied within the corporate structure.

Recommendations

We recommend that LG&E:

23. Post organizational charts and employee information showing the required information for all of the business units engaged in the sales function.

24. Revise its organizational chart postings to show the position of all Energy and Marketing Affiliates within the corporate structure.

25. Revise its organizational chart posting to clearly show that LG&E uses its service company as the employment mechanism for the Transmission Provider and its Energy and Marketing Affiliates. All postings shall be made within 7 business days of the issuance of a Final Audit Report in this docket, consistent with 18 C.F.R. § 358.4(b)(3)(iv) (2005).

Actions Already Taken by LG&E

After discussions with us, LG&E updated its posted organizational charts. We reviewed LG&E's organizational charts in January 2006, and found the revised organizational charts included more, but not all, of the information required under 18 C.F.R. § 358.4(b)(3) (2005).

8. Shared Facilities

LG&E did not post a list of the facilities shared by the Transmission Provider and LG&E's Marketing and Energy Affiliates as required by 18 C.F.R. § 358.4(b)(2) (2005).

Pertinent Guidance

The Commission's regulations state: "A Transmission Provider must post on its OASIS or Internet website, as applicable, a complete list of the facilities shared by the Transmission Provider and its Marketing and Energy Affiliates, including the types of facilities shared and their addresses."[36] This requires that when a Transmission Provider's Marketing and Energy Affiliates share facilities with any function of the Transmission Provider whose employees have access to transmission information, those shared facilities must be posted.[37]

Discussion

LG&E's Order No. 2004 information posted on its internet website in April 2005 stated: "At this time, no facilities are shared between the Transmission Provider and its Marketing and Energy Affiliates".

LG&E believed that it was required to post a list of shared facilities only if its transmission function shares facilities with its Marketing and Energy Affiliates. Since LG&E's transmission function is housed in two buildings (the Waterside control center and the Dix Dam control center) that otherwise do not house other LG&E business units, LG&E informed us that it did not believe it had any shared facilities that required posting.

---

[36] 18 C.F.R. § 358.4(b)(2) (2005).

[37] Transmission Provider is defined as follows in 18 C.F.R. § 358.3 (2005):
(a) Transmission Provider means:
(1) Any public utility that owns, operates or controls facilities used for the transmission of electric energy in interstate commerce; or
(2) Any interstate natural gas pipeline that transports gas for others pursuant to subpart A of part 157 or subparts B or G of part 284 of this chapter.
(3) A Transmission Provider does not include a natural gas storage provider authorized to charge market-based rates that is not interconnected with the jurisdictional facilities of any affiliated interstate natural gas pipeline, has no exclusive franchise area, no captive rate payers and no market power.

Virtually all of LG&E's shared service employees (many of whom have access to transmission information) occupied the same building as LG&E's two primary Marketing and Energy Affiliates, *i.e.*, LG&E's WMF, and LG&E's principal affiliated power marketer (LEM). When we pointed out to LG&E that shared service employees with access to transmission information and the Marketing and Energy affiliate employees share facilities which trigger a posting requirement, LG&E agreed to revise its posting to ensure that it is consistent with 18 C.F.R. § 358.4(b)(2) (2005).

Recommendation

We recommend that LG&E:

26. Revise its shared facilities posting to include all facilities that LG&E's Marketing and Energy Affiliates share with service employees who have access to non-public transmission information.

Actions Already Taken by LG&E

After discussions with us, LG&E revised its posting with respect to shared facilities on December 13, 2005. We reviewed the revised posting in January 2006 and found that the revised posting is not consistent with the Commission's requirements. Specifically, LG&E has not identified the facilities its Marketing and Energy Affiliates share with other LG&E functions that have access to non-public transmission information.

V. MARKET-BASED RATE TARIFF FINDING AND RECOMMENDATIONS

9. Electric Quarterly Report Inaccuracies

LG&E's Electric Quarterly Report (EQR) filing for the first quarter of 2005 contained inaccurate information for its market-based rate sales. LG&E inaccurately reported several sales transactions from its WMF to its affiliated power marketer (LEM) and reported invalid Data Universal Numbering System (DUNS) numbers for several other customers.

Pertinent Guidance

Order No. 2001 [38] provided field names for the specified information required to be filed for the EQR: transaction begin date and transaction end date fields are provided for reporting the date and hour the transaction began and ended, increment peaking name field for reporting full period (FP), Peak (P), and Off-peak (OP), and class name field for reporting non-firm (NF) and firm (FP) power sales. Order No. 2001 also required the reporting of DUNS numbers for all customers in the EQR, making the power sale and the transmission reporting requirements consistent and reducing possible confusion among similarly named, but different, providers of service.

Discussion

We reviewed a sample of LG&E's EQR filing specifically for the first quarter of 2005. We found that LG&E inaccurately reported sales transactions to LEM and reported invalid Data Universal Numbering System (DUNS) numbers for several other customers.

LG&E reported two "around the clock" sales to LEM on February 24, 2005 (transaction_unique_identifier 2005003000) and February 25, 2005 (transaction_unique_identifier 2005003080). LG&E sold 52 megawatts to LEM in each hour in Transaction 2005003000 for $47.00 during the peak period and $31.00 during the off-peak period. LG&E sold 104 megawatts to LEM in each hour in Transaction

[38] *Revised Public Utility Filing Requirements*, Order No. 2001, FERC Stats. & Regs., Regulations Preambles, ¶ 31,127 (2002), *order on reh'g,* Order No. 2001-A, 100 FERC ¶ 61,074 (2002), *order on reconsideration and clarification*, Order No. 2001-B, 100 FERC ¶ 61,342 (2002); Order No. 2001-C, 101 FERC ¶ 61,314 (2002); Order No. 2001-D, 102 FERC ¶ 61,334 (2003); Order No. 2001-E, 105 FERC ¶ 61,352 (2003); Order No. 2001-F, 106 FERC ¶ 61,060 (2004).

2005003080 for $51.50 during the peak period and $31.50 during the off-peak period. LG&E reported the off-peak period of both transactions as beginning at 12:00 AM and ending at 11:59 PM and assigned the increment peaking name as "FP" or full period rather than "OP" or off-peak. LG&E reported the peak period of these transactions as beginning at 7:00 AM and ending at 10:59 PM and assigned the increment peaking name as "FP" or full period rather than "P" or peak.

LG&E's EQR filing included 34 unique transaction identifiers where it sold energy to LEM and reported the class name of the energy sold as "NF" or non-firm. LG&E's Code of Conduct also required these sales to LEM to be posted on an EBB where LG&E reported these same sales transactions as system firm sales. When we asked LG&E to explain the discrepancy, it explained that the EQR data showing the sales as non-firm was incorrect.

LG&E reported 10 invalid DUNS numbers in its EQR for the 1st quarter 2005 for the following customers: Barbourville Water & Electric, Bardstown Municipal Light & Water, Bardwell City Utilities, Benham Electric System, City of Madisonville, City of Paris Cómbines Utilities, El Paso Merchant Energy L.P., El Paso Merchant Energy, LP, Owensboro Municipal Utilities, and Rainbow Energy Marketing Corp..

Recommendations

We recommend that LG&E:

27. Strengthen its written procedures to ensure all data reported in future EQR filings are in compliance with Commission regulations and reflect the correction of the errors and inconsistencies identified in this Audit Report.

28. Implement procedures to validate all customer DUNS numbers.

29. Refile all EQR reports from inception to correct the increment peaking name and the class name of power it sold to LEM.

30. LG&E shall submit all procedures to OE for approval within 30 days of issuance of a Final Audit Report in this docket.

Actions Already Taken by LG&E

LG&E advised us that it would be making corrections to its EQR filings, and that such corrections were made on January 31, 2006. We expect that the revised written procedures on EQR filings will be addressed by LG&E in its implementation plan in response to this Audit Report.

VI. IMPLEMENTATION PLAN

We recommended that LG&E submit an implementation plan to the audit staff for our approval detailing LG&E's plans to comply fully with the findings and recommendations in this Audit Report. The implementation plan should describe the actions LG&E has already taken, and will take, that are consistent with and complementary to any future structural and organizational changes that LG&E may undertake.

The implementation plan should be submitted within 30 days of issuance of a Final Audit Report in this docket. In addition, LG&E shall make quarterly filings updating the audit staff of its progress on implementing the plan. The filings shall be made no later than 30 days after the end of each calendar quarter, beginning with the first quarter after this audit report is issued, and continuing until all the corrective actions are completed.

Appendix

e·on | U.S.

Michael S Beer

June 29, 2006

Mr. Bryan Craig, Director
Division of Audits
Office of Enforcement
Federal Energy Regulatory Commission
888 First Street, NE
Washington, DC 20426

RE: *Louisville Gas and Electric Company, Kentucky Utilities Company*
Docket No. PA05-9-000

Dear Mr. Craig:

This letter sets forth the response of Louisville Gas and Electric Company ("LG&E") and Kentucky Utilities Company ("KU") (collectively, the "Companies") to the draft audit report issued by the Federal Energy Regulatory Commission's ("FERC" or the "Commission"), Office of Enforcement, Division of Audits ("FERC Audit Staff") on June 14, 2006, in the above referenced docket ("Draft Audit Report"). As requested, this response addresses: (1) whether the Companies agree or disagree with each finding and recommendation set forth in the Draft Audit Report; and (2) the corrective actions planned, or taken, and target completion dates.

I. INTRODUCTION.

The Companies agree with the findings and recommendations set forth in the Draft Audit Report. Further, the Companies appreciate the opportunity to respond to the Draft Audit Report. Encouraging, facilitating, and maintaining on-going compliance with Commission's regulatory initiatives and requirements is of the highest priority to the Companies and consistent with the core values and behaviors of E.ON U.S. LLC and its parent, E.ON AG. The operational audit of the Companies' compliance with the Standards of Conduct, the Companies' Market-Based Rate Tariffs, Market-Based Rate Tariff Code of Conduct ("LG&E Code of Conduct"), and the Open Access Transmission Tariff of the Midwest Independent Transmission System Operator, Inc. (collectively, "Audit Items") has been beneficial for the Companies as the audit process revealed several areas in which the Companies could improve their existing processes and methods.

During the course of the audit, and as discussed here, the Companies have taken and will continue to take substantial steps to improve their compliance. The Companies are committed to implementing and maintaining a comprehensive internal FERC compliance program as suggested in the recent *Policy Statement on Enforcement*.[1] One of the core behaviors that defines the global E.ON corporate family is the "drive for excellence." In this regard, the Companies are committed to driving for excellence in the area of FERC regulatory compliance by implementing, monitoring, and periodically evaluating the effectiveness and efficiency of existing measures designed to ensure for full compliance.

In this regard and to clearly demonstrate the Companies' commitment to compliance, the Chairman, President, and Chief Executive Officer of the Companies has expanded the responsibilities of the Standards of Conduct Chief Compliance Officer ("CCO") to include the LG&E Code of Conduct and the Market-Based Rate Tariffs under which the Companies and any affiliates may be operating. The CCO has been further directed to prepare and implement a detailed, comprehensive compliance program that encompasses the full range of FERC regulatory obligations, and to develop and implement a strategy for enhanced training, monitoring, and auditing the effectiveness of the overall internal FERC compliance process. The Companies' ongoing commitment to compliance has the full support of the entire senior management team of E.ON U.S. LLC, as well as their commitment to support the development and the implementation of the broader FERC compliance program.

As noted in the *Policy Statement on Enforcement*, a thorough commitment to compliance must be ingrained in corporate culture. Such a commitment is established at the senior most levels of any organization and must flow down from management to front-office employees engaged in day-to-day operations. As noted above, E.ON U.S. LLC senior management is strongly committed to ensuring compliance with all applicable FERC regulatory obligations. The Companies believe that the establishment of a detailed and comprehensive internal FERC compliance program will demonstrate this commitment throughout the E.ON U.S. LLC corporate family and also to the Commission. Simply put, compliance with the letter and spirit of applicable FERC regulatory obligations is encouraged, expected, and required at all levels of our organization. Therefore, as the audit process concludes, E.ON U.S. LLC reiterates our commitment to strengthening and maintaining an effective and open culture of compliance. This commitment is an integral part of our corporate identity and reflects our core values and behaviors.

---

[1] *Enforcement of Statues, Orders, Rules and Regulations*, 113 FERC ¶ 61,068 (2005) ("*Policy Statement on Enforcement*").

II. Response to Proposed Findings and Recommendations.

The Companies sincerely appreciate FERC Audit Staff's willingness to work with our employees and, where possible, provide guidance to help strengthen our overall compliance with the Audit Items. Prior to addressing specific comments on the proposed findings and recommendations, the Companies would like to highlight their cooperation with FERC Audit Staff as the audit progressed. We believe that the spirit in which the revised procedures for the Before-the-Purchase System were developed, as well as the guidance regarding Standards of Conduct training and for strengthening compliance with the Code of Conduct Electronic Bulletin Board ("EBB") posting requirements, are positive examples of how the operational audit process can work. The Companies look forward to working with FERC Audit Staff to finalize and implement post operational audit compliance plans in accordance with the process described in the Draft Audit Report.

As noted in Section I, above, the Companies agree with the findings and recommendations set forth in the Draft Audit Report. As discussed in Section I, above, the Companies and their parent, E.ON U.S. LLC, are committed to ensuring on-going compliance with the Audit Items, as well as other applicable FERC regulatory initiatives and requirements. The Companies were frankly unsettled by the number of non-compliance findings identified by FERC Audit Staff. We trust that our willingness to act without delay to address the identified non-compliance issues and take the necessary steps to strengthen and broaden their overall compliance program is, in fact, evidence of the priority the Companies give to compliance. These priorities will not change following the conclusion of the audit. Finally, the Companies would like to emphasize the importance of the absence of findings of intent to violate applicable rules or tariffs regarding the identified areas of non-compliance.

III. Update of Corrective Actions Taken or Planned and Target Completion Dates.

The Companies agree to submit an implementation plan within 30 days of the issuance of the final audit report. The implementation plan will set forth the distinct steps that the Companies have taken, and will take, to fully comply with the findings and recommendations set forth in the final audit report. In the interim, the Companies provide the following status report on the steps that they have taken during the course of the audit to comply with the findings and recommendations of FERC Audit Staff.

A. Code of Conduct Findings and Recommendations.

1. Functional, Physical, and Operational Separation of LG&E's Wholesale Merchant Function and Affiliated Power Marketer.

The Draft Audit Report directs the Companies to take all appropriate actions necessary to ensure that wholesale merchant function employees ("WMF") are functionally, physically, and operationally separated to the maximum extent practical, as required under the LG&E Code of Conduct, from their affiliated power marketer, LG&E Energy Marketing Inc. ("LEM"). Draft Audit Report at 8-11. As discussed below, the Companies have already implemented, or propose to implement, corrective measures designed to satisfy these requirements. While the final details of the steps taken by the Companies to achieve the appropriate degree of functional, physical and operational separation required by the LG&E Code of Conduct will be set forth in their implementation plan, the Companies provide the following update.

a. Functional Separation Concerns.

The Draft Audit Report states that the functional separation between WMF and LEM is not consistent with the LG&E Code of Conduct. Draft Audit Report at 8-9. The Draft Audit Report cites two examples of the lack of appropriate functional separation between WMF and LEM. *Id.* at 8-9. The first example concerns meetings jointly attended by WMF and LEM personnel and the Senior Vice President, Energy Marketing ("SVP Energy Marketing") at which certain market information about WMF and LEM trading operations was discussed. *Id.* The second example addresses certain aspects of the job description for the SVP Energy Marketing's indicating "that the SVP Energy Marketing is expected to coordinate WMF and LEM activities to provide a greater return for the LG&E corporate family." *Id.* at 9. The Companies agree with the findings made in the Draft Audit Report regarding the functional separation between WMF and LEM and agree to implement post-audit corrective measures to improve their compliance with the LG&E Code of Conduct functional separation requirements.

In order to ensure clear and full compliance with the functional separation requirements of the LG&E Code of Conduct, the Companies propose to implement the following corrective measures. First, the Companies propose to revise the job description of the SVP Energy Marketing. All language in the current job description indicating that SVP Energy Marketing is expected to "coordinate WMF and LEM activities to provide a greater return for the LG&E corporate family" will be deleted. As revised, the job description will require the SVP Energy Marketing to exercise his corporate oversight and management responsibilities for WMF and LEM in a manner that ensures that WMF and LEM: (1) are treated as separate and distinct businesses in accordance with the functional separation requirements of the LG&E Code of Conduct; and (2) will produce the greatest return for the E.ON U.S. corporate family on an independent and stand-alone basis. Further, the revised job description will acknowledge the SVP Energy Marketing's obligation to comply with the No Conduit Rule set forth in the LG&E Code of Conduct.

Second, as discussed in Section III.A.1.b, below, the SVP Energy Marketing has discontinued holding monthly trading meetings that are jointly attended by WMF and LEM staff. Concurrent with the physical relocation of LEM to an enclosed work space on the Fourth (4th) Floor West section of the E.ON U.S. LLC Building located at 220 W. Main Street in Louisville, Kentucky ("E.ON Center"), the SVP Energy Marketing has implemented a process change and now meets with WMF and LEM separately on a monthly basis to discuss relevant business issues. Further, as noted in Section III.A.2.a, below, the Companies have implemented a process change that requires the CCO or his designee to attend any business meetings where both WMF and LEM staff are present. This process change squarely covers any meeting where the SVP Energy Marketing also may be present with both WMF and LEM staff.

Third, per prior discussions with FERC Audit Staff on or about February 6, 2006, the Companies commit to adhere to the chain of command for WMF and LEM in order to maintain separation between the SVP Energy Marketing and the execution of day-to-day WMF and LEM activities consistent with the SVP Energy Marketing's status as one of most senior executives in the E.ON U.S. LLC corporate family and the Companies' existing delegations of corporate authorities.

Together with the corrective measures designed to ensure proper physical and operational separation discussed in Sections III.A.1.b and c, below, the Companies respectfully submit that, given the relatively small size of E.ON U.S. LLC regulated and unregulated trading operations, these corrective measures will provide the functional separation required by the LG&E Code of Conduct (from both a substantive and optical perspective). The Companies will submit the specific measures for ensuring full compliance with the LG&E Code of Conduct functional separation requirements as part of their post-audit implementation plan.

b. <u>Physical Separation Concerns</u>.

The Draft Audit Report states that the physical separation between WMF and LEM is not consistent with the LG&E Code of Conduct. Draft Audit Report at 9. The Companies agree with the findings regarding physical separation concerns and, as discussed below, have implemented a number of corrective measures that assure that the physical separation of WMF and LEM is consistent with the LG&E Code of Conduct.

As a follow-up to the discussion regarding the physical proximity of WMF and LEM in their letter to FERC Audit Staff dated January 11, 2006 ("January 11 Letter"), the Companies hereby confirm that as of March 31, 2006, LEM has been physically relocated to an enclosed work space on the 4th Floor West section of E.ON Center. The enclosed LEM work space on the 4th Floor West section of the E.ON Center is secured by a card-key reader that only permits access to LEM personnel and a limited group of support personnel that may be shared consistent with requirements of the LG&E Code of Conduct, such as the CCO and designees, internal legal counsel, Energy Marketing Accounting, Trading Controls, and Operations Analysis/System Implementation.

Neither the 4th Floor of the E.ON Center nor the enclosed LEM workspace located thereon can be accessed by WMF personnel. Conversely, neither the 7th Floor of the E.ON Center nor the enclosed WMF workspace located thereon can be accessed by LEM personnel.

A full description of the specifics regarding the key card access restrictions to the enclosed LEM work space on the 4th Floor West section, and to the WMF work space on the 7th Floor North section, of the E.ON Center will be provided in the Companies' post-audit implementation plan. Further, written procedures governing the access to the WMF and LEM workspaces for authorized E.ON U.S. LLC employees and other permitted persons will be adopted by the Companies as part of comprehensive Code of Conduct compliance program.

c. <u>Operational Separation Concerns with Respect to Recorded Phone Calls</u>.

The Draft Audit Report states that the operational separation between WMF and LEM with respect to recorded phone calls on two (2) RACAL digital tape recorders is not consistent with the LG&E Code of Conduct. Draft Audit Report at 9-10. The Companies agree with these findings as set forth in the Draft Audit Report and have already undertaken measures to ensure compliance with the operational separation requirements of the LG&E Code of Conduct as it relates to recorded phone conversations. Further, as discussed below, the Companies propose to implement additional measures to ensure compliance with this aspect of the operational separation requirement.

In their January 11 Letter, the Companies proposed to implement certain internal controls to ensure appropriate operational separation under the LG&E Code of Conduct with respect to WMF and LEM trader telephone conversations using RACAL digital tape recorders. January 11 Letter at 5. The Companies continue to pursue the implementation of the corrective measures outlined in the January 11 Letter. However, the Companies hereby inform FERC Audit Staff that, on or about December 14, 2005, the RACAL digital tape recorders were replaced by two (2) NiceCall Focus III voice recording systems that contain technology that permit the "desktop review" of previously recorded conversations. One NiceCall Focus III machine is dedicated exclusively for use by LEM. The second machine is dedicated for use exclusively by WMF. The Companies believe that their investment in separate voice recording machines for LEM and WMF that contain "desktop review" technology is a substantial step towards achieving the operational separation required by the LG&E Code of Conduct with respect to recorded calls.

Distinct from the RACAL recorders, the NiceCall Focus III voice recording systems are operated on a stand-alone basis and are not interconnected in any way, physically or operationally. As noted above, these machines contain technology that allows traders to engage in desktop review of prior recorded calls. As discussed in greater detail in the Companies' post-audit implementation plan, traders for WMF and LEM are assigned specific channels on the NiceCall Focus III machine assigned to their business unit and are only permitted access to those channels.[4] In order to provide appropriate risk management and corporate oversight of trading activities, supervisory personnel within LEM and WMF are also permitted to access the recorded conversations of traders assigned to their business unit.[5] Limited access to recorded conversations is permitted by certain "shared support" personnel that are subject to the No Conduit Rule under the LG&E Code of Conduct, such as internal legal counsel, Trading Controls, Energy Accounting, Contract Administration, and the CCO and his designees.

In two distinct respects, the Companies believe that the use of the separate NiceCall Focus III machines with "desktop review" technology will help ensure on-going compliance with the operational separation requirements of the LG&E Code of Conduct. First, "desktop review" technology eliminates the need for WMF and LEM personnel to have physical access to the work space where these machines are currently stored. Second, because different NiceCall Focus III machines are used by WMF and LEM, taken together with the fact that WMF and LEM have been physically separated as described in Section III.A.1.b, above, there is no risk of personnel from one operation gaining indirect, remote access to non-public market information on the other operation's recorded lines.

As discussed in greater detail in their post audit implementation plan, the Companies propose to adopt a comprehensive set of written procedures designed to facilitate on-going compliance with LG&E Code of Conduct operational separation requirements as applied to recorded calls for both the new NiceCall Focus III machines and for historic conversations recorded on the RACAL tapes. The Companies will adopt these written procedures as part of comprehensive Code of Conduct compliance

---

[4] Because separate NiceCall Focus III machines are used by LEM and WMF, traders for LEM may only access assigned channels on the NiceCall Focus III machine that is dedicated for use exclusively by LEM. Similarly, WMF traders may only access assigned channels on the NiceCall Focus III that is dedicated for use exclusively by WMF.

[5] LEM supervisory personnel may only access voice recordings on the NiceCall Focus III machine dedicated for use exclusively by LEM. Similarly, WMF supervisory personnel may only access voice recordings on the NiceCall Focus III machine dedicated exclusively for use by WMF.

program. With regard to historic conversations recorded on the RACAL tapes, the Companies propose to implement internal controls consistent with those outlined in their January 11 Letter.

In that regard, the January 11 Letter proposed to implement a policy or set of procedures designed to ensure that: (1) trading personnel of one operation (whether WMF or LEM) will not have access to RACAL tapes of recorded conversations of the other; and (2) that anyone requesting access to RACAL tapes of recorded conversations must listen to such tapes in a location that does not permit access to phone conversations of the other group (*i.e.*, in their assigned work spaces). Specifically, the Companies proposed to develop a log book or another form of written record to document requests for access to historic conversations recorded on the RACAL tapes that requires the following information:

- The name of the person(s) seeking access to the RACAL tapes containing the recorded phone conversations;

- The name of their business unit (*e.g.*, WMF, LEM, legal or regulatory);

- A brief description of the recorded conversations on the RACAL tapes for which access to the tapes is sought;

- A brief description of the reasons for reviewing the recorded conversations on the RACAL tapes (*e.g.*, contract dispute, incorrect trade confirmation.

Finally, the Companies propose to include written procedures to provide for the periodic review by the CCO or his designee of the RACAL tape log book or other written record. These written procedures will be adopted as part of a comprehensive Code of Conduct compliance program

2. Sharing of Market Information.

a. Joint Staff Meetings Between WMF and LEM.

The Draft Audit Report states that the WMF shared marketing information through presentations at joint staff meetings in violation of the LG&E Code of Conduct. Draft Audit Report at 12-13. The Companies agree with these findings regarding joint staff meetings between WMF and LEM as set forth in the Draft Audit Report. As discussed below, the Companies have already undertaken significant measures to ensure compliance with the information sharing restrictions in the LG&E Code of Conduct and propose to formalize these measures in their post-audit implementation plan.

In June 2005, the Companies revised the agenda of the monthly trading meetings jointly attended by WMF and LEM personnel, as well as the SVP Energy Marketing and staff from Market Analysis, Trading Controls, Operations Analysis, and Fuels Management to address concerns raised by FERC Audit Staff regarding the sharing of WMF historical off-system sales ("OSS") summary information during these meetings. *See* Draft Audit Report at 14. From the period June 2005 through March 31, 2006, the Companies altered the agenda so that the presentation regarding WMF's OSS was not made until LEM employees were dismissed from the meeting. Since December 2005, the Companies have adopted certain process changes, including the requirement to have the CCO or his designee attend all business meetings jointly attended by WMF and LEM personnel. The CCO or his designee maintains a high-level agenda and/or minutes of such joint meetings.

Please note that beginning on or about April 1, 2006, the SVP Energy Marketing discontinued scheduling and holding monthly trading meetings that are jointly attended by WMF and LEM staff. The monthly trading meetings are now held by the SVP Energy Marketing with WMF and LEM staff separately. These separate meetings are also attended by staff from Market Analysis, Trading Controls, Operations Analysis, and Fuels Management, who are shared support staff under the LG&E Code of Conduct and subject to the No Conduit Rule. In accordance with the No Conduit Rule, non-public WMF or LEM market information discussed during meeting with one business unit (*i.e.*, WMF) is not shared in meetings with the other business unit (*i.e.*, LEM) and vice versa.

As discussed in greater detail in their post-audit implementation plan, the Companies propose to adopt the process changes as part of a comprehensive Code of Conduct compliance program. In addition, the Companies propose to memorialize as part of a comprehensive Code of Conduct compliance program that monthly trading meetings discussed in the Draft Audit Report are held separately with WMF and LEM staff.

b. Password Access to EMS Information.

The Draft Audit Report states that Companies password access controls to the shared Energy Management System ("EMS") were insufficient and inconsistent with the Companies' password security policy. Draft Audit Report at 13. Prior to February 2004, the Companies permitted WMF and LEM users to access the EMS using separate group accounts and passwords, rather than using unique user accounts and passwords. *Id.* As a consequence, the Draft Audit Report states that failure to require unique password access was contrary to the Companies' password security policy and increased the risk of inappropriate information access via the EMS. *Id.* The Companies agree with the findings regarding password access to EMS information as set forth in the Draft Audit Report and have already taken corrective measures to address these concerns.

As noted in the Draft Audit Report, in February 2004, the Companies have implemented individual user-ids and passwords for its current GE/Harris EMS. As required by GE/Harris vendor support requirements, a common user-id still exists solely and exclusively for maintenance purposes. However, the WMF and LEM EMS users do not have access to the vendor required common user-id and may only access the EMS through their own unique user-id and password.

The Companies are in the process of installing a new Open Systems International ("OSI") EMS. It is anticipated that the OSI EMS will become fully operational on or about December 31, 2006. As part of their post-audit operational plan, the Companies will provide an update on the status of the installation of the new OSI EMS and on a quarterly basis thereafter until the OSI EMS becomes fully operational. In addition, the Companies agree to conduct an independent review by their internal audit department or an outside audit firm when the OSI EMS is implemented to ensure that there is no unauthorized EMS screen access by WMF and LEM staff. Finally, a requirement mandating the periodic review of EMS access requirements will be adopted as part of the Companies' existing Standards of Conduct compliance program and the proposed comprehensive Code of Conduct compliance program.

3. Posting Information on Sales to Affiliates at Market-Based Rates.

a. Accessibility of EBB Information to Market Participants.

The Draft Audit Report raised a number of concerns regarding the accessibility of the Companies EBB to market participants. Draft Audit Report at 15-16. The Companies agree with the findings regarding the accessibility of EBB information to market participants.

As noted in the Companies' January 11 Letter, as of January 2006, a link to the EBB, entitled "LEM Transactions" was posted on the left-hand column of regulatory page of the E.ON U.S. LLC Internet site. January 11 Letter at 6 n.2. The regulatory page of the E.ON U.S. LLC Internet site can be accessed at the following web address: http://www.eon-us.com/regulatory.asp. Subsequently, to ensure the easiest possible ratepayer and market participant access to the EBB, the Companies posted an additional EBB link, entitled "LEM Transactions EBB," on the lower right-hand corner of the homepage of E.ON U.S. LLC Internet site. The homepage of the E.ON U.S. LLC Internet site can be accessed at the following web address: http://www.eon-us.com/home.asp. Accordingly, as of the date hereof, there are two (2) separate and easily accessible links on the E.ON U.S. LLC Internet site for interested parties to view the EBB.

A copy of the regulatory page and the home page of the E.ON U.S. LLC Internet site containing the existing links to the Companies' EBB on are appended hereto as Attachment A.

b. Posted Offers to Sell on the EBB.

The Draft Audit Report states that Companies' efforts to post offers to sell to LEM on the EBB were not consistent with posting requirements set forth in Paragraphs 7 and 8 of the LG&E Code of Conduct. Draft Audit Report at 16-17. The Companies agree with the findings regarding posted offers to sell on the EBB as set forth in the Draft Audit Report. As noted in their January 11 Letter, the Companies proposed to develop process changes to facilitate significantly stronger compliance with the posting requirements set forth Paragraphs 7 and 9[1] of the LG&E Code of Conduct.

A presentation generally outlining the proposed process changes was made and submitted to FERC Audit Staff on December 16, 2005. The process changes proposed in the presentation and described below are based on the Companies' understanding of existing Commission precedent addressing the need for implementing the EBB requirement when regulated utilities engage in market-based sales with unregulated affiliates. Specifically, Commission precedent is clear that when traditional public utilities engage in power sales to an affiliated power marketer, public utilities may have an incentive to favor their affiliated marketer to the detriment of captive ratepayers.[6] Such behavior can take place when a public utility and its affiliated power marketer transact in ways that result in a

---

[6] The paragraphs in the currently effective LG&E Code of Conduct originally accepted for filing by the Commission in Docket No. ER99-1623 were incorrectly numbered. There are a total of nine (9) paragraphs. The eighth and ninth paragraph of the LG&E Code of Conduct are incorrectly labeled paragraphs 9 and 10.

[7] *See Detroit Edison Co., et al.*, 80 FERC ¶ 61,348 at 62,198 (1997); *see also Aquila, Inc.*, 101 FERC ¶ 61,331 at P 8 (2002); *FirstEnergy Corp. et al.*, 94 FERC ¶ 61,182 at 61,630 (2001); *Alliant Services Co.*, 85 FERC ¶ 61,344 at 62,335 (1998).

diversion of benefits from the public utility (and its captive ratepayers) to the affiliated power marketer (and its shareholders).[7]

To avoid the diversion of benefits from captive ratepayers to shareholders, the Commission requires that utilities engaging in power sales to affiliated marketers must price such transactions at a rate no lower than the rate the utilities charge to non-affiliates.[8] The requirement to "simultaneously" post offers to, and executed sales with, an affiliate marketer on an EBB is intended to provide transparency to this affiliate sales process. The purpose for providing such transparency is to allow interested third-parties (*i.e.*, ratepayers and market participants), as well as the Commission itself, to independently verify whether such affiliate transactions were priced in accordance with this standard.

As a practical business and operational matter, it is extremely difficult, if at all possible, to comply with the literal language set forth in Paragraphs 7 and 9 of the LG&E Code of Conduct, *i.e.*, mandating the simultaneous posting of: (1) offers to LEM; and (2) executed affiliate power sales transactions. Due to the pace of modern trading operations, transactions are negotiated and executed within minutes. Traders in the WMF cannot in such a short period of time: (1) survey the market and develop a credible picture of the prevailing market price for a given product; (2) negotiate with several counterparties to obtain the best sales price possible; (3) execute trades; and (4) post offers to, and executed sales with, LEM at the same time they take place.

The proposed EBB posting process changes discussed with FERC Audit Staff are intended to reflect the practical realities of engaging in real-time trading activities within a small organization. More importantly, the Companies believe that the process changes discussed with FERC Audit Staff are consistent with both the intent and spirit of the Commission's existing precedent and policies designed to prevent affiliate abuse and self-dealing described above.

The Companies believe that addressing these operational realities in a practical manner must have been considered by the Commission when it established the simultaneous posting requirements codified in Paragraphs 7 and 9 of the LG&E Code of Conduct. Further, the Companies believe that these operational realties must have been intended when Paragraphs 7 and 9 were written. As proposed to FERC Audit Staff, the EBB posting process changes will provide ratepayers, market participants, and the Commission with a workable, easily accessible, and transparent mechanism for monitoring on a real-time basis whether sales by the Companies to LEM may result in an improper diversion of benefits from ratepayers due to the failure to price such transactions in a manner that complies with the LG&E Code of Conduct.

The Companies recognize the complexities of this particular issue and look forward to working with FERC Audit Staff to finalize these process changes as part of their post-audit implementation plan. The final process changes for posting offers to sell on the EBB will be adopted as part of a comprehensive Code of Conduct compliance program. As discussed in greater detail in the Companies' post-audit implementation plan, E.ON U.S. LLC senior management will supervise the formal roll-out sessions for implementing the final EBB posting process changes. Specifically, the roll out and subsequent training sessions will not only discuss the purpose and application of the EBB posting

---

[8] *Id.*

[9] *Id.*

process, they will also emphasize the importance of this process and the need to vigilantly assure compliance therewith. After the initial roll out, the Companies propose to conduct periodic internal reviews and follow-up training to ensure on-going compliance.

c. Prices of Affiliate Sales.

The Draft Audit Report states that the Companies did not have any written procedures or other controls for WMF traders to determining whether sales to LEM were consistent with the affiliate pricing provisions set forth in Paragraph 6 of the LG&E Code of Conduct. Draft Audit Report at 17. The Draft Audit Report notes that the WMF traders established the market price for next-hour energy sales to LEM through telephone queries with potential counterparties and through broker quotes. *Id.* The Draft Audit Report further states that, although no evidence that WMF traders transacted with LEM at less than market price, WMF traders did not generally employ strong controls to establish the market prices. *Id.* The Companies agree with the findings relating to the pricing of affiliate sales as set forth in the Draft Audit Report.

The process changes for posting offers to sell on the EBB discussed in Section III.A.3.b, above, were addressed in the presentation presented to FERC Audit Staff on December 16, 2005. In relevant part, the process changes outline the steps by which WMF traders must determine whether posted offers to sell to LEM hourly or daily energy are priced no lower than prevailing market prices for each product. These procedures provide for a specific period after an offer to sell to LEM is posted on the EBB during which WMF traders must exercise commercially reasonable efforts (*i.e.*, due diligence) to survey the market and determine whether non-affiliates have any interest in pursuing an opportunity equivalent to that being offered to LEM. The WMF traders may not transact with LEM until after the specified posting period has expired. If, at the expiration of such period, an offer to sell to LEM posted on the EBB is the best and highest price available (*i.e.*, no lower than the price offered or sold to non-affiliates), the Companies may execute the sale to LEM.

As discussed in greater detail in the Companies' post-audit implementation plan, these procedures will be adopted as part of a comprehensive Code of Conduct compliance program.

d. EBB Postings in 2001.

The Draft Audit Report identifies certain concerns that took place in 2001 relating to whether, for a period of time, the EBB was properly used to post offers and sales from WMF to LEM to support a long-term sales obligation that LEM had with Morgan Stanley. Draft Audit Report at 17. The Companies agree with the findings regarding the EBB postings in 2001 as set forth in the Draft Audit Report. E.ON U.S. LLC senior management is deeply committed to ensuring that the Companies use the EBB to properly post offers and sales to LEM in accordance with the LG&E Code of Conduct requirements.

E.ON U.S. LLC has and will continue to commit the time and resources necessary to internal compliance measures designed to facilitate an enhanced understanding of, and compliance with, the EBB posting requirements set forth in the LG&E Code of Conduct. As discussed with FERC Staff at length and proposed in the Companies' December 16, 2005 presentation, E.ON U.S. LLC management believes that significantly enhanced compliance with the EBB posting requirements may be achieved through:

- Implementing a revised user friendly EBB offer matrix that contains key deal parameters and clearly articulates appropriate definitions and user guidelines;

- Providing formal employee training regarding the purpose, application and importance of the EBB posting process (including potential ramifications for non-compliance -- both internally and externally);

- Implementing additional internal controls designed to ensure that, when offers to LEM are made and sales are executed, all required EBB postings are timely made and consistent with the LG&E Code of Conduct; and

- Providing periodic follow-up training and reviewing the revised EBB posting process periodically to ensure that it is operating correctly.

As will be discussed in greater detail in the Companies post-audit implementation plan, because a true culture of compliance flows down from the top of corporate organizations, the Companies propose that the process changes for the EBB posting process will be formally rolled out by current E.ON U.S. LLC management. Senior management will ensure proper oversight of employee training sessions regarding the scope, application and importance of the EBB posting process. In addition, management will ensure that appropriate resources are dedicated to conduct periodic internal reviews and follow-up training to ensure on-going compliance with the EBB posting requirements.

B. STANDARDS OF CONDUCT FINDINGS AND RECOMMENDATIONS.

As discussed in Section I above, as part of their post-audit implementation plan, the Companies propose to undertake a comprehensive review of their Standards of Conduct Written Procedures ("SCWP") posted on the E.ON U.S. LLC Internet site, and revise and update the SCWP as necessary. The comments below respond to the specific findings and recommendations set forth in the Draft Audit Report.

1. Disclosure of Transmission and Customer Information.

a. Disclosure of Transmission Information by Telephone.

The Draft Audit Report identifies three instances where transmission function employees of the Companies disclosed non-public transmission information to regulated generation dispatchers during the course of reliability-related Transmission Line Loading Relief/generation redispatch events ("Generation Redispatch Events"). Draft Audit Report at 20-21. Because the Companies regulated generation dispatchers are organizationally and functionally housed in the WMF business unit (an Energy Affiliate), the identified transmission information was disclosed through non-public communications. *Id.* at 17. The Companies agree with the factual findings regarding the disclosure of transmission information by telephone as set forth in the Draft Audit Report, subject to the following factual clarification. The identified disclosures of transmission information occurring by telephone during Generation Dispatch Events were posted on the Standards of Conduct Page of the E.ON U.S. LLC Internet site on January 13, 2006. The posting can be found at: http://www.eon-us.com/regulatory/disclosure_of_information.pdf.

In their January 11 Letter, the Companies proposed to develop certain process changes to ensure that any information disclosed by transmission function employees or by a third-party Transmission Provider are promptly reported to the CCO for evaluation and, where necessary, posted on the OASIS or the E.ON U.S. LLC Internet site. January 11 Letter at 8-9. In the intervening period, the process changes outlined below have been implemented by the Companies. These process changes govern the behavior of both transmission function employees and regulated generation dispatchers during Generation Redispatch Events and include the following concepts:

- During Generation Redispatch Events, transmission function employees are only to provide specific redispatch instructions.

- Absent emergency circumstances affecting system reliability, transmission function employees may not provide regulated generation dispatchers with information regarding the cause of the Generation Redispatch Event.

- Transmission function employees and regulated generation dispatchers are required to document and provide prompt notice to the CCO or his designee of any instance in which non-public transmission information is disclosed to regulated generation dispatchers, whether by transmission function employees or any other third party (including, but not limited to, a security coordinator or reliability authority, or another Transmission Provider).

- In the event of any disclosures of non-public transmission information by a third-party (including, but not limited to, a security coordinator or reliability authority, or another Transmission Provider), apart from notifying the CCO, transmission function employees and regulated generation dispatchers will comply with the No Conduit Rule.

- Regulated generation dispatchers should <u>not</u> trade on any non-public transmission information improperly disclosed to them.

As will be described in greater detail in the Companies' post-audit compliance plans, the process changes outlined above will be converted into written procedures and incorporated into the Companies' existing SCWPs and future Standards of Conduct training programs sponsored by the Companies.

b. <u>Disclosure of Transmission Information at a Meeting Attended by Transmission and Marketing Employees</u>.

The Draft Audit Report identifies one meeting in which transmission personnel and marketing personnel were present at which the Companies' transmission personnel disclosed non-pubic information regarding the status of two transmission projects. Draft Audit Report at 21. The Draft Audit Report notes that the disclosure was not posted on the OASIS in a timely manner. *Id.* As noted in the Draft Audit Report, no evidence was found that Companies' Energy or Marketing Affiliates traded on this information. *Id.* The Companies agree with the findings regarding the disclosure of transmission information at a meeting attended by transmission and marketing employees as set forth in the Draft Audit Report.

The Companies posted the non-public transmission information disclosed in the meeting identified in the Draft Audit Report on the E.ON U.S. LLC Internet site at: http://www.eon-us.com/regulatory/disclosure_of_information.pdf on March 31, 2006. Further, beginning in April 2005, the Companies adopted certain process changes in response to concerns raised by FERC Audit Staff that cross-functional business meetings between transmission function employees and employees of Energy or Marketing Affiliates ("C/F Meetings") create the potential for the sharing of non-public transmission information. Since April 2005, the CCO or his designee has attended all identified C/F Meetings. The CCO or his designee maintains a high-level agenda and/or minutes for each meeting. The C/F Meetings include not only senior level staff meetings but also meetings attended by line level Transmission Function Employees and employees of Energy Affiliates.

In addition, the Companies propose to continue to conduct periodic "function specific" training sessions, including those with E.ON U.S. LLC senior management, to ensure that employees at all levels of the E.ON U.S. LLC organization fully understand the scope and application of the Standards of Conduct restrictions on the sharing of non-public transmission information, including the requirements to post disclosures of non-public transmission information. As discussed in greater detail in their post-audit implementation plan, the Companies propose to: (1) adopt procedures detailing the need for the CCO or his designee to be present at all C/F Meetings as described above and incorporate such procedures into its SCWPs; and (2) will provide additional information about the "function specific" training sessions.

c. Disclosure of Customer Load Data by E-Mail.

The Draft Audit Report states that a transmission function employee e-mailed a marketing employee specific, non-pubic customer load information on a monthly basis through February 2005. Draft Audit Report at 21. The Draft Audit Report notes that the Companies failed to post these disclosures on the OASIS in a timely manner. *Id.* The Companies agree with the findings regarding the disclosure of customer load data by e-mail as set forth in the Draft Audit Report.

As noted in the posted disclosure, the customer information at issue involved after-the-fact, monthly historic peak transmission load information. This information is used by the Midwest ISO to invoice the Companies for their Schedule 10 charges under the Midwest ISO's Open Access Transmission Tariff (or Module B of the Day 2 TEMT). The WMF is responsible for budgeting, approving and paying the Midwest ISO invoice. The non-public customer load data disclosed via e-mail to marketing employee identified in the Draft Audit Report was posted on the E.ON U.S. LLC Internet site on March 31, 2006 at: http://www.eon-us.com/regulatory/disclosure_of_information.pdf.

Since February 2005, the Companies have implemented process changes to ensure that transmission function employees no longer provide non-public customer load information to Energy or Marketing Affiliate employees. As will be discussed in greater detail in their post-audit compliance plan, these process changes will be memorialized and incorporated into the Companies' SCWPs. In addition, the Companies agree to perform a review of all transmission and customer information shared through e-mail distribution in order to ensure that such information is not inappropriately shared with Energy or Marketing Affiliate employees. The Companies further propose to implement new written procedures that require the periodic review of such e-mail distributions to ensure ongoing compliance with the Standards of Conduct.

2. Standards of Conduct Training.

The Draft Audit Report states that the Companies' Standards of Conduct training program was inconsistent with the Commission's regulations and the Companies' SCWP and implementation plans. Draft Audit Report at 24. During the audit, FERC Audit Staff discussed the Companies' training with the CCO, his designees and other E.ON U.S. LLC officials. Subsequently, on November 10, 2005, the Companies submitted a letter outlining an enhanced Standards of Conduct training program. *Id.* FERC Audit Staff found the proposed compliance plan to be consistent with Order No. 2004 and proposed findings and recommendations. *Id.* The Companies accept the findings regarding Standards of Conduct training as set forth in the Draft Audit Report.

The 2005 edition of the Companies' Standards of Conduct training took place from November 17, 2005 through December 31, 2005. The 2005 training program required the participation of all employees in the E.ON U.S. LLC corporate family at the manager level and above, as well as employees with the words or phrases "supervisor," "team leader," or "group leader" in their job title.[9] In addition, the Companies trained all employees in the following lines of business: (1) the Companies' Transmission Function; (2) All Energy Marketing Personnel (regulated and unregulated); (3) Information Technology; (4) Accounting and Finance; (5) Corporate Communications; (6) Legal; and (7) Regulatory. These functional areas of responsibility were selected because employees in such areas have or may have access to non-public transmission information through the Companies' financial books of account, records or contracts or real-time, day-to-day operations.

As noted in the Draft Audit Report, in 2005, the Companies significantly increased the number of employees who have received the Edison Electric Institute ("EEI")-developed, electronic Standards of Conduct training program by eighty percent (80%), from approximately 610 to approximately 1,100. The Companies are committed to further strengthening their training program to ensure that on a going-forward basis it remains consistent with Commission requirements and internal training plans. As part of this process, the Companies will memorialize new process changes for ensuring that new employees and transfers receive the appropriate Standards of Conduct training. The Companies' future Standards of Conduct training plans will be discussed in greater detail in their post-audit implementation plan.

---

[10] Included within the group of employees described above are certain field personnel in the Companies' distribution function, such as managers and supervisors of substation construction crews which respond to outages that can affect the Companies integrated transmission and distribution systems. In addition, this group of employees included all managers, supervisors or above higher ranking personnel that are employed by Energy Affiliates that operate generation facilities on behalf of other investor-owned utilities

3. Controls Used to Limit Access to the System Control Centers.

a. CCO Permission to Visit the System Control Centers.

The Draft Audit Report states the Companies did not follow Section IV.A.2.b of their posted SCWP to control and track access of its marketing employees to their Waterside and Dix Dam system control centers. Draft Audit Report at 27. The Companies agree with the findings regarding CCO permission to visit the system control centers as set forth in the Draft Audit Report. Below the Companies discuss certain corrective measures that have already been undertaken to address concerns identified by FERC Audit Staff.

As noted in the Draft Audit Report, on January 10, 2005, the Companies revised the Standards of Conduct page of the E.ON U.S. LLC website to include a link titled, "Request for Access to Transmission Control Center." The link can be found at: http://www.eon-us.com/regulatory/soc_request_access.asp. The link provides instructions for the submission of written, electronic requests by employees of Energy and Marketing seeking access to the Transmission Control Centers. Consistent with Section IV.A.2.b of the Companies' SCWP, the link directs Energy or Marketing Affiliate employees to submit the following information to the CCO as part of a request for access to the to the Transmission Control Centers:

- The proposed time and date that access to the Transmission Control Centers is required; and
- A verifiable and legitimate business purpose for seeking access to such facilities.

Consistent with Section IV.A.2.b of SCWP, the link states that the CCO shall: (1) review such requests and approve or deny them; and (2) maintain electronic copies of all forms submitted and his decision to approve or deny such requests for a period of three (3) years.

Subsequently, on February 2, 2006, the Companies posted an announcement on the E.ON U.S. LLC Intranet site prominently announcing the new "Request for Access to Transmission Control Center" link on the Standards of Conduct section of Regulatory page of the E.ON U.S. LLC Internet site. The announcement of the "Request for Access to Transmission Control Center" link was made available to all E.ON U.S. LLC employees as part of the daily "News Transmission" published on the E.ON U.S. LLC Intranet site. In addition, an e-mail blast was distributed to all employees highlighting the "Request for Access to Transmission Control Center" link as a headline story in the "News Transmission" items for February 2, 2006.

As will be discussed in greater detail in their post-audit implementation plan, the Companies will further review and strengthen its system control center access procedures as directed in the Draft Audit Report. Further, the Companies commit to internally announce on a periodic basis the "Request for Access to Transmission Control Center" link on the Standards of Conduct section of Regulatory page of the E.ON U.S. LLC Internet site.

b. Controls on Visitors Entering the System Control Centers.

The Draft Audit Report states that the written log books documenting visitors' access to the Waterside and Dix Dam system control centers were inconsistent with Companies' SCWPs. Draft Audit Report at 28. Specifically, the written log books did not collect some pertinent information that was required in Section IV.A.2.b of the SCWPs. *Id.* The Companies accept the findings regarding controls on visitors entering the system control centers as set forth in the Draft Audit Report

The Companies confirm that by January 13, 2006, the log books located at the Waterside and Dix Dam system control centers were in place and updated to contain the same fields of inquiry set forth in Section IV.A.2.b of the SCWP, which include the following:

- The name of the transmission customer;

- Date and time of the visit;

- The name of the Transmission Function Employee or other Company Personnel (as that term is defined in the SCWP) hosting the transmission customer;

- Whether the transmission customer is an affiliate; and

- The purpose of the visit.

The update of the logbooks to include these fields of inquiry ensures consistency with the Companies' existing SCWP procedures and creates an audit trail that allows for independent verification regarding whether the Companies' Energy and Marketing Affiliate employees had access to system control centers in any way that differed from non-affiliate transmission customers. The Companies agree to the recommendations set forth in the Draft Audit Report and will provide greater detail regarding additional corrective measures (if any are required) in their post-audit implementation plan.

c. <u>Access to Transmission Information Once Inside the System Control Center</u>.

The Draft Audit Report raises concerns that non-transmission function employee visitors to Waterside and Dix Dam system control centers could gain access through a direct, external line of sight to certain non-public transmission information posted on monitors and boards within these facilities actual transmission system control rooms. Draft Audit Report at 29. The Companies agree with the findings regarding access to transmission information once inside the system control centers as set forth in the Draft Audit Report.

In their January 11 Letter, the Companies committed to install by January 13, 2006 certain temporary, but effective, covers on all windows on doors, or windows that serve as partitions or walls for purposes of impeding a direct view into the control rooms at Waterside and Dix Dam. The Companies hereby confirm that such temporary covers were in fact installed by January 13, 2006. Further, the Companies committed to implement a permanent solution through the use of frosted glass or another similar technique by the end of the first quarter of 2006. By this letter, the Companies hereby confirm that, prior to the end of the first quarter of 2006, permanent window frosting treatment covers were installed all windows on doors, or windows that serve as partitions or walls for purposes of impeding a direct view into the control rooms at Waterside and Dix Dam.

4. Organizational Charts.

The Draft Audit Report states that Companies have not properly posted certain organizational charts showing: (1) employee information required for all business units in the sales function; (2) the position of all Energy and Marketing Affiliates with the E.ON U.S. LLC family corporate structure; and (3) that the Companies use a service company as an employment mechanism for the Transmission Provider and for its Energy and Marketing Affiliates. Draft Audit Report at 30-32. The Companies agree with the findings regarding the posting of organizational charts as set forth in the Draft Audit Report.

On Friday, June 16, 2006, the Companies and FERC Audit Staff held a conference call for purposes of ensuring that the Companies fully satisfied the organizational chart posting requirements and concerns articulated in the Draft Audit Report. The Companies appreciate FERC Audit Staff's cooperation and help in this process. As will be discussed in greater detail in their post-audit implementation plan, the Companies will post revised organizational charts in accordance with the directives and guidance provided by FERC Audit Staff on the June 16th call.

5. Shared Facilities.

The Draft Audit Report states that the Companies did not post a list of facilities Shared by the Transmission Provider and the Companies' Energy and Marketing Affiliates. Draft Audit Report at 33. Further, the Draft Audit Report notes that virtually all of the Companies shared service Employees occupied the same building as their two primary Marketing and Energy Affiliates -- WMF and LEM. *Id.* at 34. When FERC Audit Staff pointed out that the shared services employees with access to transmission information and the Marketing and Energy Affiliate shared facilities which trigger a posting requirement, the Companies agreed to revise its posting to ensure that it is consistent with 18 C.F.R. § 358.4(b)(2) (2005). The Companies agree with the findings regarding shared facilities as set forth in the Draft Audit Report and corrected the posting.

C. MARKET-BASED RATE TARIFF FINDING AND RECOMMENDATIONS.

The Draft Audit Report states that, for the first quarter of 2005, the Companies' Electric Quarterly Reports ("EQRs") contained inaccurate information for its sales made pursuant to their joint market-based rate tariff. Draft Audit Report at 35. Specifically, the Companies inaccurately reported several sales transactions from its WMF to LEM and reported invalid Data Universal Numbering System ("DUNS") numbers for several other customers. The Companies accept the findings regarding EQRs as set forth in the Draft Audit Report.

As noted in the Draft Audit Report, on January 31, 2006, the Companies made certain corrections to its EQR filings. The Companies agree to implement the proposed recommendations set forth in the Draft Audit Letter regarding: (1) strengthening the Companies' written procedures to ensure that all data reported in future EQR filings are in compliance with Commission regulations and reflect the correction of errors and inconsistencies identified in the Draft Audit Report; (2) implementing procedures to validate all customer DUNS numbers; and (3) refiling all EQR reports from inception to correct the incremental peaking name and class name of power sold to LEM. The refiling referenced in subsection (3) above has been completed.

The proposed corrective measures designed ensure the accuracy and sufficiency of the Companies' EQR reports and ensure compliance with their joint market-based rate tariff will be submitted with the Companies' post-audit implementation plan.

IV. CONCLUSION.

On behalf of E.ON U.S. LLC, I would like to thank the FERC Audit Staff for their time, effort and commitment to ensuring that the Companies are in full compliance with the Audit Items. I would like to again affirm E.ON U.S. LLC's commitment to meeting its obligations under the Standards of Conduct, the Code of Conduct, its Market-Based Rate Tariff and all other applicable FERC imposed regulatory obligations.

Sincerely,

Michael S. Beer
Vice President, Federal Regulation and Policy and
Standards of Conduct Chief Compliance Officer
E.ON U.S. LLC

on behalf of
Louisville Gas and Electric Company &
Kentucky Utilities Company

cc: Carl Coscia
Lyle Hanagami
Eliot Wessler
FERC, Office of Enforcement, Division of Audits

Steven D. Phillips
E.ON U.S. LLC

R. Michael Sweeney, Jr.
Hunton & Williams LLP

ATTACHMENT A

search

After more than three successful years as part of the E.ON family, LG&E Energy, the parent company of Louisville Gas and Electric Company, Kentucky Utilities Company and Western Kentucky Energy, is now E.ON U.S.

LG&E, KU, and WKE — the companies that customers are most familiar with — will continue to operate under their current identities. more

06.28.2006
LG&E Coal Ash Recycled; Land to be used for Green Space

06.27.2006
E.ON U.S. Capital Corp. Announces Pricing Of Tender Offer and Consent Solicitation

06.20.2006
LG&E Announces Regular Dividends On Preferred Stock

LG&E
- For the Home
- For the Business

KU/ODP
- For the Home
- For the Business

LG&E/KU Standards of Conduct

Effective September 22, 2004, E.ON U.S. and other U.S. energy companies must comply with new Federal Energy Regulatory Commission ("FERC") orders requiring organizational separation between transmission and energy and marketing affiliates.

Collectively, the new orders are referred to as the Standards of Conduct and are fundamentally based on two guiding principles. First, a Transmission Provider's employees engaged in transmission system operations must function independent from the employees of its Marketing and Energy Affiliates. Secondly, a Transmission Provider must treat all transmission customers, affiliated and non-affiliated, on a non-discriminatory basis and must not operate its transmission system to preferentially benefit its marketing or energy affiliates. The Final Rule requires organizational separation of all energy and marketing affiliates, including natural gas marketing affiliates, from the electric transmission function.

The Standards of Conduct require that a Transmission Provider must post certain information on its corporate website or its OASIS. Links to all of the requisite information, whether residing here or on the LG&E/KU page of the MISO OASIS, are provided below. Please contact the Chief Compliance Officer if you have any questions.

- How to Report a Potential Violation of the Standards of Conduct
- Request for Access to Transmission Control Center
- FERC Orders - Standard of Conduct Regulation (PDF)
- FERC Orders - Order No. 2004 (PDF)
- FERC Orders - Order No. 2004-A (PDF)
- FERC Orders - Order No. 2004-B (PDF)
- LG&E/KU Compliance Procedures (PDF)
- LG&E/KU February 2004 Compliance Filing (PDF)
- Chief Compliance Officer
- Marketing & Energy Affiliate Listing (PDF)
- Shared Facilities Listing
- Notices of Employee Transfers (PDF)
- Organizational Charts - Overall Corporate Structure (PDF)
- Organizational Charts - Chain of Command (PDF)
- Organizational Charts - Transmission Chain of Command
- Organizational Charts - Energy Marketing Chain of Command
- Organizational Charts - Job Titles & Descriptions (PDF)
- Potential Merger Partners as Affiliates (none at this time)
- Disclosure of Information (PDF)
- Voluntary Consent to Disclose Information (none at this time)
- Log of Tariff Administration Matters and Discounts
- MISO OASIS
- LG&E/KU page of MISO OASIS

Download PDF (103K)

Terms of Use Contractor Health and Safety Site Wellness Site

Kentucky Utilities Company
Case No. 2009-00548
Historical Test Period Filing Requirements

Filing Requirement
807 KAR 5:001 Section 10(6)(m)
Sponsoring Witness: Valerie L. Scott

Description of Filing Requirement:

The most recent Federal Energy Regulatory Commission Form 1 (electric), Federal Energy Regulatory Commission Form 2 (gas), or Automated Reporting Management Information System Report (telephone) and Public Service Commission Form T (telephone);

Response:

KU's most recent FERC Form 1 for the year ended December 31, 2008, is attached.

KU FERC Form 1 – December 31, 2008

THIS FILING IS	
Item 1: ☐ An Initial (Original) Submission	OR ☐ Resubmission No. ____

Form 1 Approved
OMB No. 1902-0021
(Expires 7/31/2008)
Form 1-F Approved
OMB No. 1902-0029
(Expires 6/30/2007)
Form 3-Q Approved
OMB No. 1902-0205
(Expires 6/30/2007)

FERC FINANCIAL REPORT
FERC FORM No. 1: Annual Report of Major Electric Utilities, Licensees and Others and Supplemental Form 3-Q: Quarterly Financial Report

State Corporation Commission of the Commonwealth of Virginia

These reports are mandatory under the Federal Power Act, Sections 3, 4(a), 304 and 309, and 18 CFR 141.1 and 141.400. Failure to report may result in criminal fines, civil penalties and other sanctions as provided by law. The Federal Energy Regulatory Commission does not consider these reports to be of confidential nature

Exact Legal Name of Respondent (Company)	Year/Period of Report
Kentucky Utilities Company	End of 2008/Q4

Virginia State Corporation Commission Supplemental List of Schedules

Title of Schedule	Reference Page No.	Remarks
Production Fuel and Oil Stocks	VASCC C	Kentucky Utilities Company
Particulars Concerning Certain other Income Accounts	VASCC L	Kentucky Utilities Company
Construction Work in Progress and Completed Construction - Not Classifed - Electric	VASCC O - O-9	Kentucky Utilities Company
Sales to Railroads and Railways and Interdepartmental Sales	VASCC P	Kentucky Utilities Company
Rent from Electric Property and Interdepartmental Rents	VASCC P	Kentucky Utilities Company
Sales of Water and Water Power	VASCC Q	Kentucky Utilities Company
Miscellaneous Service Revenues and Other Electric Revenues	VASCC Q	Kentucky Utilities Company
Electric Plant in Service	VASCC 204 - 207	Virginia Only
Electric Operating Revenues Commonwealth of Virginia	VASCC 300 - 301	Virginia Only
Electric Operating Revenues - Virginia State Corporation Commission Jurisdiction Only	VAJUR 300 - 301	VASCC Juris Only

Name of Respondent: KENTUCKY UTILITIES COMPANY

This report is: (1) _X_ An Original (2) ___ A Resubmission

Date of Report (Mo, Da, Yr)

Year of Report: December 31, 2008

PRODUCTION FUEL AND OIL STOCKS (Included in Account 151)

1. Report below the information called for concerning production fuel and oil stocks.
2. Show quantities in tons of 2000 lb. Barrels (42 gals.), or Mcf., whichever unit of quantity is applicable.
3. Each kind of coal or oil should be shown separately.
4. If the respondent obtained any of its fuel from its own coal mines or oil or gas lands or leases or from affiliated companies, a statement should be submitted showing the quantity of such fuel so obtained, the quantity used and quantity on hand, and cost of the fuel classified as to the nature of the costs and expenses incurred with appropriate adjustment for the inventories at beginning and end of year.

Line No.	Item (a)	Total Cost (b)	KINDS OF FUEL AND OIL: COAL Quantity (c)	COAL Cost (d)	OIL Quantity (e)	OIL Cost (f)	GAS Quantity (g)	GAS Cost (h)
1	On hand beginning of year	41,770,628	797,804	38,196,560	42,878	3,474,914	12,011	99,154
2	Received during year	536,627,800	8,417,765	481,973,824	91,974	11,052,182	3,668,004	43,601,794
3	TOTAL	578,398,428	9,215,569	520,170,384	134,852	14,527,096	3,680,015	43,700,948
4	Used during year (specify departments)							
5	Electric	505,690,393	8,137,283	453,526,506	70,068	8,558,412	3,667,605	43,605,475
6								
7								
8								
9								
10								
11	Sold or transferred							
12	TOTAL DISPOSED OF							
13	BALANCE END OF YEAR	72,708,035	1,078,286	66,643,878	64,784	5,968,684	12,410	95,473

KINDS OF FUEL AND OIL - Continued

Line No.	Item (i)	Total Coal Cost	High Sulfur Cost (j)	Low Sulfur Cost (k)	Total Quantity (l)	High Sulfur Quantity (m)	Low Sulfur Quantity (n)	(o)
14	On hand beginning of year	38,196,560	13,659,349	24,537,211	797,804	376,656	421,148	
15	Received during year	481,973,824	206,647,702	275,326,122	8,417,765	4,349,863	4,067,902	
16	TOTAL	520,170,384	220,307,051	299,863,333	9,215,569	4,726,519	4,489,050	
17	Used during year (specify departments)							
18	Electric	453,526,506	184,364,787	269,161,719	8,137,283	4,062,478	4,074,805	
19								
20								
21								
22								
23								
24	Sold or transferred							
25	TOTAL DISPOSED OF							
26	BALANCE END OF YEAR	66,643,878	35,942,264	30,701,614	1,078,286	664,041	414,245	

Next Page is L

Name of Respondent	This report is:	Date of Report	Year of Report
KENTUCKY UTILITIES COMPANY	(1) X An Original (2) ___ A Resubmission	(Mo, Da, Yr)	December 31, 2008

PARTICULARS CONCERNING CERTAIN OTHER INCOME ACCOUNTS

1. Report in this schedule the information specified in the instructions below for the respective other income accounts. Provide a conspicuous subheading for each account and show a total for the account. Additional columns may be added for any account if deemed necessary.
2. Merchandising, jobbing and Contract Work (Accounts 415-416)-Describe the general nature of merchandising, jobbing and contract activities. Show revenues by class of activity, operating expenses classified as to operation, maintenance, depreciation, rents, and net income before taxes. Give the bases of any allocations of expenses between utility and merchandising, jobbing and contract work activities.
3. Nonutility Operations (Accounts 417 and 417.1)-Describe each nonutility operation and show revenues, operating expenses classified as to operation, maintenance, depreciation, rents, amortization and net income before taxes, from the operation. Give the bases of any allocations of expenses between utility and nonutility operations. The book cost of property classified as nonutility operations should be included in Account 121.
4. Nonoperating Rental Income (Account 418)-For each major item of miscellaneous property included in Account 121, Nonutility Property, which is not used in operations for which income is included in Account 417, but which is leased or rented to others, give name of lessee, brief description of property, effective date and expiration date of lease, amount of rent revenues, operating expenses classified as to operation, maintenances, depreciation, rents, amortization, and net income before taxes, from the rentals. If the property is leased on a basis other than that of a fixed annual rental, state the method of determining the rental. Minor items may be grouped by classes, but the number of items so grouped should be shown. Designate any leases which are associated companies.
5. Interest and Dividend Income (Account 419)-Report interest and dividend income, before taxes, identified as to the asset account or group of accounts in which are included the assets from which the interest of dividend income was derived. Income derived from Investments, Accounts 123, 124, and 136 may be shown in total. Income from sinking and other funds should be identified with the related special funds. Should also expenses, included in Account 419 as required by the uniform system of accounts
6. Miscellaneous Nonoperating Income (Account 421)-Give the nature and source of each miscellaneous nonoperating income, and expense and the amount thereof for the year. Minor items may be grouped by classes.

Line No.	Item (a)	Amounts (b)
1		
2	Account 416 - Cost and Expenses of Merchandising, Job. & Contract Work	
3	Total Account 416	-
4		
5	Account 417.0 - Revenues from Nonutility Operations	
6	Revenues from nonutility operations	1,355,192
7	Total Account 417.0	1,355,192
8		
9	Account 418 - Nonoperating Rental Income	
10	Total Rent Revenues	25
11	Operating Expenses	-
12	Operation	-
13	Maintenance	-
14	Depreciation	-
15	Total	-
16	Net Income Before Taxes	25
17		
18	Total Account 418	25
19		
20	Account 419 - Interest and Dividend Income	
21	Interest from Associated Companies	362,147
22	Interest from State Tax Refunds	300,000
23	Interest from Financial Holdings	7,385
24	Interest from Special Funds	561,372
25	Dividends - Non Associated Company	137,500
26	Interest from Other Loans & Receivables	114,737
27	Total Account 419	1,483,141
28		
29	Account 421 - Misc. Nonoperating Income	
30	Misc Nonoperating Income	(29,543)
31	Mark-to-Market Income - Nonhedging	833,146
32	Total Account 421	803,603
33		
34		
35		
36		

Name of Respondent	This report is:	Date of Report	Year of Report
KENTUCKY UTILITIES COMPANY	(1) _X_ An Original (2) ___ A Resubmission	(Mo, Da, Yr)	December 31, 2008

CONSTRUCTION WORK IN PROGRESS AND COMPLETED CONSTRUCTION NOT CLASSIFIED -ELECTRIC (Accounts 107 and 106)

1. Report below descriptions and balances at end of year of projects in process of construction and completed construction not classified for projects actually in service. For any substantial amounts of completed construction not classified for plant actually in service explain the circumstances which have prevented final classification of such amounts to prescribed primary accounts for plant in service.
2. The information specified by this schedule for Account 106, Completed construction Not Classified-Electric, shall be furnished even though this account is included in the schedule, Electric Plant in Service, pages 401-403, according to a tentative classification by primary accounts.
3. Show items relating to "research and development" projects last under a caption Research and Development: (See account 107, Uniform System of Accounts).
4. Minor projects may be grouped.

Line No.	Description of Project (a)	Construction Work in Progress-Electric (Account 107) (b)	Completed Construction Not Classified-Electric (Account 106) (c)	Estimated Additional Cost of Project (d)
1	**STEAM PRODUCTION**			
2	TC2 - KU	$ 396,423,467		$ 66,576,533
3	BROWN 1, 2, 3 FGD	$ 233,726,240		$ 117,939,417
4	TC2 AQCS KU	$ 152,293,728		$ 32,706,272
5	KU SOX PROGRAM - GHENT 2 FGD SYSTEM	$ 140,838,104		
6	BROWN ASH POND EXPANSION, PHASE I	$ 18,186,020		$ 33,331,899
7	GH3 FGD	$ 6,453,203		
8	GHENT 1 CONTROLS MODERNIZATION	$ 5,186,779		
9	GHENT 4 CONTROLS MODERNIZATION	$ 4,960,348		$ 172,652
10	GH2 CT CELL REBUILD	$ 3,511,494		$ 571,506
11	BR2 REHEAT INLET & OUTLET HEADER	$ 3,170,091		$ 2,645,949
12	GHENT 2 CONTROLS MODERNIZATION	$ 3,141,868		$ 1,733,132
13	SO3 SORBENT INJECTION	$ 2,565,236	$ 7,426,033	$ 9,292,730
14	GHENT SO2 COMMON	$ 1,872,738	$ 131,804,746	$ 350,126
15	GHENT SPCC COMPLIANCE MODIFICATIONS	$ 1,445,319		$ 1,032,309
16	GH4 FGD	$ 1,223,066	$ 159,937,989	
17	GH3 CATALYST LAYER PURCHASE & INSTALLATION	$ 1,142,172		$ 1,804,828
18	E.W. BROWN UNIT 3 SCR CONCEPTUAL ENGINEERING	$ 1,009,718		$ 1,990,282
19	GHENT ASH POND/LANDFILL	$ 1,008,465		$ 991,535
20	FUEL SUPPLY MANAGEMENT SYSTEM	$ 942,509		$ 843,491
21	MERCURY MONITORING KU	$ 941,211		$ 308,753
22	TRIMBLE COUNTY ASH/GYPSUM PONDS	$ 921,539		$ 458,461
23	BR3 COOLING TOWER STORM DAMAGE REPAIRS	$ 813,369		$ 21,761
24	BR1 AIR HEATER BASKET REPLACEMENT	$ 623,093		$ 14,173
25	DEVELOPMENT TY OIL CONTAINMENT SPCC	$ 527,081		
26	GH4 ASH PIPE REPLACEMENT	$ 436,131		$ 21,869
27	GH1 CT CELL 1-1 REBUILD	$ 426,823		$ 177
28	REVISED BR2 TURBINE BLADES	$ 424,297		$ 205,829
29	GH4 CT CELL 4-5 REBUILD	$ 417,311		$ 9,689
30	GH3 CT CELL 3-6 REBUILD	$ 416,234		$ 10,766
31	GH3 CT CELL 3-5 REBUILD	$ 410,849		$ 16,151
32	BR1-1 SBAC REPLACEMENT	$ 387,553		$ 13,283
33	GH DOWNRIVER FLOATING WORK BARGE	$ 359,455		$ 537,545
34	GH MOORING CELL C-4	$ 322,819		$ 1,181
35	COAL BARGE UNLOADER BUCKET & CHAIN REPLACEMENT	$ 299,837		$ 91,163
36	DEVELOPMENT HF OIL CONTAINMENT SPCC	$ 284,598		
37	GHENT CONVEYOR BELT REPLACEMENT	$ 273,117		$ 16,883
38	BR2 PRECIPITATOR PLATE REPLACEMENT	$ 271,161		$ 1,164,634
39	GH1 ID FAN TRANSFORMER	$ 235,675		$ 14,325
40	TY 480V SWITCHGEAR REPLACEMENT	$ 210,875		$ 60,125
41	MAXIMO LICENSES	$ 186,734		
	TOTAL	$ 1,176,440,172	$ 437,171,600	$ 368,133,046

Next Page is O-1

Name of Respondent	This report is:	Date of Report	Year of Report
KENTUCKY UTILITIES COMPANY	(1) _X_ An Original (2) ___ A Resubmission	(Mo, Da, Yr)	December 31, 2008

CONSTRUCTION WORK IN PROGRESS AND COMPLETED CONSTRUCTION NOT CLASSIFIED -ELECTRIC (Accounts 107 and 106)

1. Report below descriptions and balances at end of year of projects in process of construction and completed construction not classified for projects actually in service. For any substantial amounts of completed construction not classified for plant actually in service explain the circumstances which have prevented final classification of such amounts to prescribed primary accounts for plant in service.
2. The information specified by this schedule for Account 106, Completed construction Not Classified-Electric, shall be furnished even though this account is included in the schedule, Electric Plant in Service, pages 401-403, according to a tentative classification by primary accounts.
3. Show items relating to "research and development" projects last under a caption Research and Development: (See account 107, Uniform System of Accounts).
4. Minor projects may be grouped.

Line No.	Description of Project (a)	Construction Work in Progress-Electric (Account 107) (b)	Completed Construction Not Classified-Electric (Account 106) (c)	Estimated Additional Cost of Project (d)
1	UMS GROUP INVESTMENT EVALUATION MODEL	$ 173,243		$ 1,757
2	TY 5-4 EL MILL CONVERSION	$ 162,615		$ 59,385
3	GH 4 4-2 CCW HEAT EXCHANGER	$ 152,237		$ 26,763
4	GH4 GENERATOR REWEDGE	$ 147,129		$ 76,871
5	GH MISCELLANEOUS MOTORS	$ 143,058		$ 106,942
6	BR1 LOWER DEAD AIR SPACE ABATEMENT	$ 135,699		
7	GH2 CT CELL 2-6 REBUILD	$ 129,688		$ 327,813
8	GH2 CT CELL 2-5 REBUILD	$ 129,688		$ 327,813
9	BR3 CONTROL ROOM HVAC DEVELOPMENT	$ 129,654		$ 257,346
10	TY3 5-1 EL CONVERSION	$ 128,244		$ 71,705
11	GR MAIN BUILDING ROOF	$ 126,430		$ 3,570
12	GR3 DISTRIBUTED CONTROL SYSTEM UPGRADE	$ 118,927		
13	BR 1-2 SERVICE WATER PUMP REBUILD	$ 117,994		$ 995,099
14	GH2 AUXILIARY CONDENSATE 2-2 RETUBE	$ 116,613		$ 36,387
15	STEAM PRODUCTION - MINOR PROJECTS	$ 1,653,380	$ 8,662,096	$ 2,527,213
16				
17	**HYDRAULIC POWER**			
18	DX3 OVERHAUL	$ 1,399,263		$ 3,549,840
19	DEVELOPMENT DIX CRANE ACCESS ROAD	$ 129,384		$ 20,616
20	HYDRAULIC POWER - MINOR PROJECTS	$ 64,994	$ 11,732	$ 102,072
21				
22	**OTHER PRODUCTION**			
23	BR CT7 A/B CONVERSION - KU	$ 6,391,713		
24	BR CT9 MODIFICATIONS	$ 686,722		$ 16,181
25	BR CT UNDERGROUND PIPE SPCC	$ 627,368		$ 1,029,586
26	BR CT6 QUENCH NOZZLE REPLACEMENT	$ 154,832		$ 28,069
27	OTHER PRODUCTION - MINOR PROJECTS	$ 193,616	$ 210,168	$ 77,859
28				
29	**TRANSMISSION**			
30	DEVELOPMENT FOR TRIMBLE COUNTY UNIT # 2	$ 42,479,239		$ 26,520,761
31	LOUDON AVE TO LANSDOWN 69KV DOUBLE CIRCUIT	$ 4,691,177		$ 1,554,335
32	N. AMERICAN STAINLESS 345-138 KV450 MVA TRANSFORMER	$ 4,470,709		
33	BR ASH POND EXPANSION - TRANSMISSION LINE RELOCATION	$ 4,195,754		
34	PRIORITY REPLACEMENT TRANSMISSION LINES	$ 3,065,416		
35	SPCC MODIFICATIONS FOR KU	$ 1,605,833		
36	MISCELLANEOUS SUBSTATION PROJECTS - KU	$ 1,433,143	$ 139,561	
37	FAWKES 138-69KV, 150 MVA	$ 1,354,957		$ 31,150
38	NAS TAP 345KV LINE	$ 1,275,880		
39	PRIORITY TRANSMISSION LINE	$ 1,262,028		
40	STORM DAMAGE TRANSMISSION LINE	$ 1,056,537		
41	GHENT-KENTON 138 KV LINE - P2 POLE REPLACEMENT	$ 732,251		$ 82,231
	TOTAL	$ 1,176,440,172	$ 437,171,600	$ 368,133,046

Name of Respondent	This report is:	Date of Report	Year of Report
KENTUCKY UTILITIES COMPANY	(1) _X_ An Original (2) ___ A Resubmission	(Mo, Da, Yr)	December 31, 2008

CONSTRUCTION WORK IN PROGRESS AND COMPLETED CONSTRUCTION NOT CLASSIFIED -ELECTRIC (Accounts 107 and 106)

1. Report below descriptions and balances at end of year of projects in process of construction and completed construction not classified for projects actually in service. For any substantial amounts of completed construction not classified for plant actually in service explain the circumstances which have prevented final classification of such amounts to prescribed primary accounts for plant in service.
2. The information specified by this schedule for Account 106, Completed construction Not Classified-Electric, shall be furnished even though this account is included in the schedule, Electric Plant in Service, pages 401-403, according to a tentative classification by primary accounts.
3. Show items relating to "research and development" projects last under a caption Research and Development: (See account 107, Uniform System of Accounts).
4. Minor projects may be grouped.

Line No.	Description of Project (a)	Construction Work in Progress-Electric (Account 107) (b)	Completed Construction Not Classified-Electric (Account 106) (c)	Estimated Additional Cost of Project (d)
1	GHENT 345KV BREAKER ADDITION	$ 629,509		$ 148,131
2	PARAMETER UPGRADE TRANSMISSION LINE	$ 430,973		
3	LYNCH TO POCKET 69KV HOLMES MILL	$ 391,664		$ 156,155
4	SHELBYVILLE-SIMPSONVILLE 69KV THERMAL UPGRADE	$ 373,727		$ 616,494
5	CRITICAL SPARE 138/69 KV TRANSFORMER	$ 367,705		$ 582,030
6	KU TRANSMISSION BLANKET	$ 310,012		
7	K7 PARAMETER UPGRADES TRANSMISSION LINE	$ 295,512		
8	MISCELLANEOUS TRANSMISSION CAPITAL	$ 290,745		
9	HIGHWAY 52 RELOCATION RICHMOND	$ 277,094		
10	INNOVATION DRIVE SUBSTATION 138KV TAP	$ 269,950		$ 599,277
11	HORSECAVE TRANSFORMER SUB 799 RECONDUTOR TAP TO SUB 611	$ 265,139		$ 73,017
12	UK MEDICAL CENTER CONTROL HOUSE RELOCATION	$ 257,237		
13	REPLACE FAILED HARLAN TRANSFORMER	$ 242,556		$ 93,701
14	LEBANON EAST SUBSTATION	$ 232,036		$ 126,016
15	NEW FACILITIES TRANSMISSION LINE	$ 198,190		
16	REPLACE UNDERRATED 69KV BREAKERS FAWKES SUBSTATION	$ 194,998		$ 18,809
17	TAYLOR CO TRANSFORMER	$ 183,753		
18	GARRARD COUNTY HIGH SCHOOL	$ 179,919		
19	HIGBY MILL UK MEDICAL CENTER SYSTEM PARAMETERS	$ 174,546		$ 394,004
20	DETROIT HARVESTER SECTION OF PARIS-LEXINGTON PLANT	$ 173,262		$ 191,775
21	RECONDUCTOR PARKERS MILL TAP 69KV	$ 167,597		$ 98,361
22	LOUDEN AVENUE HAEFLING 138KV HIGHWAY RELOCATION	$ 167,563		$ 206,396
23	MILLERSBURG CONTROL HOUSE REPLACEMENT	$ 164,141		$ 135,639
24	NEW FACILITIES TRANSMISSION LINE	$ 161,125		
25	TRANSMISSION LINE RELOCATION KU	$ 133,243		
26	OPEN SYSTEM INTERNATIONAL ENERGY MANAGEMENT SYSTEM	$ 127,375		$ 11,916
27	KU REMOTE TERMINAL UNIT PURCHASE	$ 121,012		
28	PURCHASE SPARE TRANSMISSION CIRCUIT BREAKERS	$ 113,776		$ 20,182
29	HARRODSBURG-ADD 69KV BREAKERS FOR CUSTOMER	$ 112,379		$ 267,615
30	DELVINTA 824 CARRIER ADDITION	$ 109,270		
31	TRANSMISSION - MINOR PROJECTS	$ 2,257,524	$ 8,505,835	$ 24,221,213
32				
33	**DISTRIBUTION**			
34	PURCHASE PROPERTY FOR INNOVATION DR. SUB. #428-1	$ 3,853,688		
35	INSTALL LEBANON JUNCTION SUB	$ 1,812,414		
36	W360 LTC REBUILD	$ 1,483,468		$ 178,862
37	NEW BUSINESS SERVICE - U/G - SHELBYVILLE	$ 1,401,943		
38	PURCHASE OF METERS	$ 1,384,274		
39	STORM PROJECT	$ 1,321,114		
40	NEW ELECTRIC SERVICE - O/H - NORTON	$ 1,304,846		
41	AIR GAS SUBSTATION	$ 1,287,203		$ 987,797
	TOTAL	$ 1,176,440,172	$ 437,171,600	$ 368,133,046

Name of Respondent	This report is:	Date of Report	Year of Report
KENTUCKY UTILITIES COMPANY	(1) X An Original (2) ___ A Resubmission	(Mo, Da, Yr)	December 31, 2008

CONSTRUCTION WORK IN PROGRESS AND COMPLETED CONSTRUCTION NOT CLASSIFIED -ELECTRIC (Accounts 107 and 106)

1. Report below descriptions and balances at end of year of projects in process of construction and completed construction not classified for projects actually in service. For any substantial amounts of completed construction not classified for plant actually in service explain the circumstances which have prevented final classification of such amounts to prescribed primary accounts for plant in service.
2. The information specified by this schedule for Account 106, Completed construction Not Classified-Electric, shall be furnished even though this account is included in the schedule, Electric Plant in Service, pages 401-403, according to a tentative classification by primary accounts.
3. Show items relating to "research and development" projects last under a caption Research and Development: (See account 107, Uniform System of Accounts).
4. Minor projects may be grouped.

Line No.	Description of Project (a)	Construction Work in Progress-Electric (Account 107) (b)	Completed Construction Not Classified-Electric (Account 106) (c)	Estimated Additional Cost of Project (d)
1	NEW ELECTRIC SERVICE - O/H - PINEVILLE	$ 1,190,212		
2	PURCHASE TRANSFORMER 315	$ 1,068,301		
3	PUBLIC WORKS RELOCATION - O/H - LEXINGTON	$ 1,003,728		
4	BRYANT ROAD #3 SUBSTATION & TEMPORARY TRANSFORMER	$ 938,428		$ 539,537
5	ADD TRANSFORMER HORSE CAVE INDUSTRIAL	$ 930,561		$ 60,639
6	STORMS FEB 5 & 6	$ 866,977		
7	PURCHASE PROPERTY LEXINGTON EAST AREA SUBSTATION	$ 788,353		$ 38,977
8	KU GENERAL RELIABILITY	$ 782,279		$ 97,563
9	CONSTRUCT LEBANON EAST SUB	$ 772,068		$ 204,932
10	SCM REPAIR/REPLACE FAILED TRANSFORMERS	$ 760,977		
11	CITY OF BARDSTOWN SUB	$ 749,919		$ 255,081
12	PURCHASE TRANSFORMERS 236	$ 703,164		
13	PURCHASE 161X69 SPARE TRANSFORMER	$ 693,043		
14	TROUBLE ORDERS O/H 246	$ 639,383		
15	ADD TRANSFORMER UNION UNDERWEAR	$ 633,411		$ 26,589
16	DISTRIBUTION RELIABILITY 156	$ 631,501		
17	REPLACE SHUN PIKE TRANSFORMER	$ 575,775		
18	STAMPING GROUND INSTALL 10 MVA TRANSFORMER	$ 548,358		$ 438,656
19	BELL COUNTY COAL GARMEADA #2	$ 495,746		$ 445,211
20	TROUBLE ORDERS O/H 256	$ 473,587		
21	NEW BUSINESS RESIDENTIAL 216	$ 470,092		
22	REPLACE TRANSFORMER 7/14 WOODLAWN	$ 461,610		$ 101,190
23	REPLACE 69/34 TRANSFORMER DORCHESTER	$ 438,507		
24	SCM EARL GREEN RIVER PLANT TRANSFORMER	$ 429,999		$ 5,001
25	PUBLIC WORKS RELOCATION - O/H - ELIZABETHTOWN	$ 428,645		
26	NEW BUSINESS RESIDENTIAL - U/G - LEXINGTON	$ 411,271	$ 2,021,518	
27	ROGERS GAP DISTRIBUTION	$ 406,447		
28	REPAIR/REPLACE DEFECTIVE STREET LIGHTS 366	$ 386,397		
29	WINTER STORM 2-11	$ 374,402		
30	DISTRIBUTION CAPACITORS KU	$ 371,803		$ 103,197
31	PURCHASE TRANSFORMERS 366	$ 364,539		
32	PURCHASE TRANSFORMERS 256	$ 349,717		
33	TROUBLE ORDERS 216	$ 337,618		
34	REPAIR REPLACE DEFECTIVE STREET LIGHTS 256	$ 332,114		
35	PURCHASE TRANSFORMER 246	$ 326,048		
36	PUBLIC WORKS RELOCATION - O/H - DANVILLE	$ 306,348		
37	BROWN 1, 2, 3 FGD	$ 305,969		
38	INSTALL NEW 795 CIRCUIT TO NESTLE PLAN 2	$ 304,805		
39	CONSTRUCT NEW CIRCUIT FROM BRYANT TEMPORARY SUB	$ 294,965		$ 26,359
40	SUBSTATION ABB TYPE TRANSFORMER REPLACEMENT	$ 291,042		
41	REPLACE TRANSFORMER AT KY STATE HOSPITAL SUB #587	$ 274,679		$ 246,321
	TOTAL	$ 1,176,440,172	$ 437,171,600	$ 368,133,046

Name of Respondent	This report is:	Date of Report	Year of Report
KENTUCKY UTILITIES COMPANY	(1) _X_ An Original (2) ___ A Resubmission	(Mo, Da, Yr)	December 31, 2008

CONSTRUCTION WORK IN PROGRESS AND COMPLETED CONSTRUCTION NOT CLASSIFIED -ELECTRIC (Accounts 107 and 106)

1. Report below descriptions and balances at end of year of projects in process of construction and completed construction not classified for projects actually in service. For any substantial amounts of completed construction not classified for plant actually in service explain the circumstances which have prevented final classification of such amounts to prescribed primary accounts for plant in service.
2. The information specified by this schedule for Account 106, Completed construction Not Classified-Electric, shall be furnished even though this account is included in the schedule, Electric Plant in Service, pages 401-403, according to a tentative classification by primary accounts.
3. Show items relating to "research and development" projects last under a caption Research and Development: (See account 107, Uniform System of Accounts).
4. Minor projects may be grouped.

Line No.	Description of Project (a)	Construction Work in Progress-Electric (Account 107) (b)	Completed Construction Not Classified-Electric (Account 106) (c)	Estimated Additional Cost of Project (d)
1	SCM EARLINGTON SUBSTATION REPLACEMENT (S&C FUSES)	$ 266,224		$ 25,476
2	WINCHESTER WATER WORKS	$ 254,763		$ 13,737
3	NEW BUSINESS COMMERCIAL 426	$ 251,108		
4	WINDSTREAM TELEPHONE COMPANY POLE REPLACEMENT	$ 249,740		
5	KU DISTRIBUTION POWER FACTOR CORRECTION	$ 247,660		$ 167,340
6	NEW BUSINESS COMMERCIAL 216	$ 244,147		
7	NEW BUS INDUSTRIAL - U/G - ELIZABETHTOWN	$ 239,590		
8	OUTAGE MANAGEMENT SYSTEM UPGRADE	$ 238,661		$ 6,946
9	INNOVATION WEST CIRCUIT	$ 237,062		$ 141,100
10	TATES CREEK RD HIGHWAY RELOCATION	$ 235,520		$ 154,814
11	REPLACE DEFECTIVE EQUIPMENT - O/H - PINEVILLE	$ 234,199		
12	ELIZABETHTOWN - STORM RESTORATION	$ 232,034		
13	NEW BUSINESS RESIDENTIAL 426	$ 230,581		
14	SCM TRANSFORMER REWINDERS	$ 229,670		$ 73,268
15	LONDON-STORM RESTORATION	$ 226,445		
16	TOOLS AND EQUIPMENT 256	$ 218,137		
17	KU MOBILE INFRASTUCTURE	$ 214,118		
18	TOOLS AND EQUIPMENT 315	$ 211,362		
19	NEW BUSINESS RESIDENTIAL - O/H - LEXINGTON	$ 209,646	$ 1,007,979	
20	TOOLS AND EQUIPMENT 246	$ 207,294		
21	STRATTON PIKE REBUILD	$ 206,772		
22	INNOVATION U/G EXIT CIRCUITS	$ 194,510		$ 39,361
23	UNION UNDERWEAR CIRCUIT WORK	$ 190,563		$ 11,339
24	HIGHWAY RELOCATION KY1577	$ 189,564		
25	BOGGS LANE	$ 185,147		$ 4,853
26	PURCHASE TRANSFORMERS 766	$ 178,199		
27	LEXINGTON STORM RESTORATION	$ 177,308		
28	SYSTEM ENHANCEMENTS - EXISTING CUSTOMERS - LEXINGTON	$ 176,958	$ 62,674	
29	SHELBYVILLE STORM RESTORATION	$ 176,242		
30	PUBLIC WORKS RELOCATION - O/H - LONDON	$ 169,772		
31	PAYNES DEPOT RD (US 62) HIGHWAY	$ 168,552		$ 66,093
32	NEW BUS RESIDENTIAL - O/H - LONDON	$ 167,027	$ 241,621	
33	DISTRIBUTION RELIABILITY 246	$ 166,661		
34	HORSE CAVE RECONDUCTORING	$ 165,066		
35	EARLINGTON STORM RESTORATION	$ 164,483		
36	KU PC & PRINTER INFRASTRUCTURE	$ 164,430		
37	HORSE CAVE INDUSTRIAL SUBSTATION DISTRIBUTION WORK	$ 159,632		
38	SCM REPLACE BREAKERS	$ 157,951		
39	TOOLS AND EQUIPMENT 156	$ 157,517		
40	PURCHASE TRANSFORMERS 156	$ 157,126		
41	PUBLIC WORKS RELOCATION - O/H - MAYSVILLE	$ 154,891		
	TOTAL	$ 1,176,440,172	$ 437,171,600	$ 368,133,046

Name of Respondent	This report is:	Date of Report	Year of Report
KENTUCKY UTILITIES COMPANY	(1) _X_ An Original (2) ___ A Resubmission	(Mo, Da, Yr)	December 31, 2008

CONSTRUCTION WORK IN PROGRESS AND COMPLETED CONSTRUCTION NOT CLASSIFIED -ELECTRIC (Accounts 107 and 106)

1. Report below descriptions and balances at end of year of projects in process of construction and completed construction not classified for projects actually in service. For any substantial amounts of completed construction not classified for plant actually in service explain the circumstances which have prevented final classification of such amounts to prescribed primary accounts for plant in service.
2. The information specified by this schedule for Account 106, Completed construction Not Classified-Electric, shall be furnished even though this account is included in the schedule, Electric Plant in Service, pages 401-403, according to a tentative classification by primary accounts.
3. Show items relating to "research and development" projects last under a caption Research and Development: (See account 107, Uniform System of Accounts).
4. Minor projects may be grouped.

Line No.	Description of Project (a)	Construction Work in Progress-Electric (Account 107) (b)	Completed Construction Not Classified-Electric (Account 106) (c)	Estimated Additional Cost of Project (d)
1	NEW BUSINESS RESIDENTIAL - O/H - NORTON	$ 152,126	$ 1,453,929	
2	LONDON FAWN VALLEY ESTATES SUBDIVISION U/G SYSTEM	$ 152,049		$ 47,282
3	ADD REGULATORS AT ANDOVER	$ 148,703		$ 23,297
4	PURCHASE TRANSFORMERS	$ 148,156		
5	NEW BUSINESS INDUSTRIAL	$ 144,749		
6	SYSTEM ENHANCEMENTS - NEW CUSTOMERS - RICHMOND	$ 140,938	$ 184,601	
7	KU GENERAL RELIABILITY	$ 138,942		
8	NEW DOUBLE CIRCUIT TO CITATION BLVD.	$ 135,394		$ 27,131
9	KU SUBS REMOTE TERMINAL UNIT INSTALLS FOR EKPC METERING	$ 134,851		
10	TROUBLE ORDERS	$ 134,605		
11	NEW BUSINESS COMMERCIAL - O/H - LEXINGTON	$ 134,295	$ 581,748	
12	BRYANT ROAD #3 EXIT CIRCUIT	$ 133,402		
13	FOURMILE RECONDUCTOR ELECTRIC	$ 131,587		$ 4,763
14	PUBLIC WORKS RELOCATION - O/H - RICHMOND	$ 128,010		
15	DISTRIBUTION RELIABILITY	$ 124,344		
16	PUBLIC WORKS RELOCATION - O/H - NORTON	$ 119,676		
17	KY 519 HIGHWAY RELOCATION	$ 117,757		$ 71,153
18	PUBLIC WORKS RELOCATION - O/H - SHELBYVILLE	$ 116,073		
19	KU STORM WORK	$ 114,997		
20	SCM CENTRAL SPARTA UPGRADE	$ 114,592		$ 66,709
21	NEW BUSINESS SUBDIVISION - U/G - PINEVILLE	$ 113,275		
22	LEXINGTON AREA IMPROVEMENTS	$ 108,407		$ 11,524
23	NEW BUSINESS SERVICE - U/G - LEXINGTON	$ 106,938	$ 8,028,534	
24	RELOCATIONS CUSTOMER REQUEST	$ 104,197	$ 207,186	
25	NEW BUSINESS RESIDENTIAL - O/H - EARLINGTON	$ 102,022	$ 1,074,505	
26	WISE CIRCUIT	$ 101,773		$ 11,217
27	SYSTEM ENHANCEMENT - EXISTING CUSTOMERS EARLINGTON	$ 100,763	$ 498,467	
28	PURCHASE TRANSFORMER	$ 100,641		
29	NEW BUSINESS RESIDENTIAL - O/H - PINEVILLE	$ 100,634	$ 524,498	
30	DISTRIBUTION - MINOR PROJECTS	$ 4,018,932	$ 100,858,679	$ 10,896,513
31				
32	**GENERAL PLANT**			
33	SAP FOR CUSTOMER CARE SYSTEM - KU	$ 22,356,920		$ 6,613,860
34	CUSTOMER CARE SYSTEM - TECHNOLOGY KU	$ 5,957,824		
35	CUSTOMER CARE SYSTEM - CUSTOMER SERVICE KU	$ 4,211,193		
36	LAND MOBILE RADIO SYSTEM BUILDOUT	$ 3,239,664		$ 1,474,324
37	CUSTOMER CARE SYSTEM - DEVELOPMENT KU	$ 1,226,793		
38	CUSTOMER CARE SYSTEM - KU BUSINESS INTELLIGENCE	$ 716,216		
39	EVA REPLACEMENT PROJECT	$ 486,066		
40	TIER C REPLACEMENT KU	$ 384,335		$ 22,576
41	EXTEND FIBER TO GREEN RIVER	$ 364,365		$ 21,035
	TOTAL	$ 1,176,440,172	$ 437,171,600	$ 368,133,046

Name of Respondent	This report is:	Date of Report	Year of Report
KENTUCKY UTILITIES COMPANY	(1) X An Original (2) ___ A Resubmission	(Mo, Da, Yr)	December 31, 2008

CONSTRUCTION WORK IN PROGRESS AND COMPLETED CONSTRUCTION NOT CLASSIFIED -ELECTRIC (Accounts 107 and 106)

1. Report below descriptions and balances at end of year of projects in process of construction and completed construction not classified for projects actually in service. For any substantial amounts of completed construction not classified for plant actually in service explain the circumstances which have prevented final classification of such amounts to prescribed primary accounts for plant in service.
2. The information specified by this schedule for Account 106, Completed construction Not Classified-Electric, shall be furnished even though this account is included in the schedule, Electric Plant in Service, pages 401-403, according to a tentative classification by primary accounts.
3. Show items relating to "research and development" projects last under a caption Research and Development: (See account 107, Uniform System of Accounts).
4. Minor projects may be grouped.

Line No.	Description of Project (a)	Construction Work in Progress-Electric (Account 107) (b)	Completed Construction Not Classified-Electric (Account 106) (c)	Estimated Additional Cost of Project (d)
1	NORTH KY BACKBONE RENOVATION	$ 340,494		$ 900,131
2	COMPUTER TELEPHONE INTEGRATION REPLACEMENT KU	$ 267,260		$ 38,368
3	CUSTOMER CARE SYSTEM - CHANGE MANAGEMENT KU	$ 241,834		
4	ORACLE FINANCIAL/MATERIAL APPLICATIONS 11.5.10.2 UPGRADE	$ 204,880		
5	ORACLE ISUPPORT PORTAL	$ 177,579		$ 9,246
6	MISCELLANEOUS KU BUSINESS OFFICE	$ 150,395		
7	AVAYA UPGRADES REMOTE KU SYSTEMS	$ 149,553		$ 447
8	DEVELOP KU CAMPUS NETWORK	$ 148,382		$ 1,618
9	KU CARPET AND TILE REPLACEMENT	$ 145,397		
10	ACCESS SWITCH ROTATION	$ 144,707		$ 1,933
11	SERVER HARDWARE REFRESH	$ 142,649		
12	LEXINGTON PURCHASE E-Z HAULER	$ 132,373		
13	BACKUP STRATEGY EXPANSION PROJECT	$ 128,632		
14	KU INTERNAL REQUESTS	$ 122,366		
15	ELIZABETHTOWN STOREROOM PAVING	$ 108,052		
16	NAS NETWORK ATTACHED STORAGE	$ 103,333		
17	SHELBYVILLE STOREROOM PAVING	$ 102,508		
18	GENERAL PLANT - MINOR PROJECTS	$ 3,496,230	$ 3,727,501	$ 2,688,156
19				
20				
21				
22				
23				
24				
25				
26				
27				
28				
29				
30				
31				
32				
33				
34				
35				
36				
37				
38				
39				
40				
41				
	TOTAL	$ 1,176,440,172	$ 437,171,600	$ 368,133,046

Name of Respondent	This report is:	Date of Report	Year of Report
KENTUCKY UTILITIES COMPANY	(1) _X_ An Original (2) ___ A Resubmission	(Mo, Da, Yr)	December 31, 2008

SALES TO RAILROADS AND RAILWAYS AND INTERNATIONAL SALES

1. Report particulars concerning sales included in Accounts 446 and 448
2. For Sales to Railroads and Railways, Account 446, give name of railroad or railway in addition to other required information. If contract covers several points of delivery and small amounts of electricity are delivered at each point, such sales may be grouped.
3. For Interdepartmental Sales, Account 448, give name of other department and basis of charge to other department in addition to other required information
4. Designate associated Companies.
5. Provide subheading and total for each account.

Line No.	Item (a)	Point of Delivery (b)	Kilowatt-hours (c)	Revenue (d)	Revenue Per KWH (e)
1	NONE				
2					
3					
4					
5					
6					
7					
8					
9					
10					
11					
12					
13					
14					
15					-

RENT FROM ELECTRIC PROPERTY AND INTERDEPARTMENTAL RENTS (Accounts 454, 455)

1. Report particulars concerning rents received included in Accounts 454 and 455.
2. Minor rents may be grouped by classes.
3. If rents are included which were arrived at under an arrangement for apportioning expenses of a joint facility, whereby the amount included in this account represents profit or return on property, depreciation, and taxes, give particulars and the basis of apportionment of such charges to Account 454 or 455.
4. Designate if lessee is an associated company.
5. Provide a subheading and total for each account.

Line No.	Name of Lessee or Department (a)	Description of Property (b)	Amount of revenue for year (c)
16	Account 454:		
17	Cingular	Pole Attachments	55,236
18	Comcast Cable Co	Pole Attachments	72,654
19	Frontier Vision Operating Partners	Pole Attachments	46,567
20	Insight Communications	Pole Attachments	103,549
21	Kentucky Data Link	Pole Attachments	57,425
22	New Wave Communications	Pole Attachments	81,339
23	Time Warner	Pole Attachments	59,661
24	Minor Items (58 items less than 5% each)	Pole Attachments	172,302
25			
26			
27			
28			
29			
30			
31	Aisin Automotive Cast Inc	Facility Charges	41,144
32	Corning Inc	Facility Charges	169,000
33	Daramic Inc	Facility Charges	41,407
34	Elf Atochem	Facility Charges	42,722
35	Pliant Corporation	Facility Charges	49,588
36	UVAW	Facility Charges	88,894
37	Minor Items (64 items less than 5% each)	Facility Charges	1,092,153
38			
39	Total Account 454		2,173,641

Next Page is Q

BLANK

Name of Respondent	This report is:	Date of Report	Year of Report
KENTUCKY UTILITIES COMPANY	(1) X An Original (2) ___ A Resubmission	(Mo, Da, Yr)	December 31, 2008

SALES OF WATER AND WATER POWER (Account 453)

1. Report below the information called for concerning revenues derived during the year from sales to others of water or water power.
2. In column (c) show the name of the power development of the respondent supplying the water or water power sold.
3. Designate associated companies.

Line No.	Name of purchaser (a)	Purpose for which water was used (b)	Power plant development supplying water or water power (c)	Amount of revenue for year (d)
1				
2	NONE			0
3				
4				
5				
6				
7				
8				
9				
10		TOTAL		0

MISCELLANEOUS SERVICE REVENUES AND OTHER ELECTRIC REVENUES (Accounts 451, 456)

1. Report particulars concerning miscellaneous service revenues and other electric revenues derived from electric utility operations during year. Report separately in this schedule the total revenues from operation of fish and wildlife and recreation facilities, regardless of whether such facilities are operated by company or by contract concessionaires. Provide a subheading and total for each account. For account 456, list first revenues realized through Research and Development ventures, see account 456.
2. Designate associated companies.
3. Minor items may be grouped by classes.

Line No.	Name of company and description of service (a)	Amount of revenue for year (b)
11		
12	Account 451	
13	Miscellaneous Service Revenues	
14	Fees for Changing, Connecting, and Disconnecting	
15	Services	1,358,829
16	TOTAL	1,358,829
17		
18	Account 456	
19	Other Electric Revenues	
20	Power Transmission Charges	8,888,020
21	Revenue Sufficiency Guarantee Make Whole Payment (MISO)	0
22	MISO Schedule 10 Offset	(3,931,171)
23	Forfeiture of Refundable Cash Advance for Construction	237,463
24	Sales Tax Collection Fee	18,193
25	Sales of Material and Supplies	543,214
27	TOTAL	5,755,719
28		
29		
30		
31		
32		
33		
34		
35		
36		
	TOTAL	7,114,548

Name of Respondent	This report is:	Date of Report	Year of Report
KENTUCKY UTILITIES COMPANY*	(1) X An Original (2) ___ A Resubmission	(Mo, Da, Yr)	December 31, 2008

ELECTRIC PLANT IN SERVICE (ACCOUNTS 101, 102, 103, AND 106)

1. Report below the original cost of electric plant in service according to the prescribed accounts.
2. In addition to the Account 101, Electric Plant in Service (Classified), this page and the next include Account 102, Electric Plant Purchased or Sold; Account 103, Experimental Electric Plant Unclassified; and Account 106, Completed Construction Not Classified - Electric. 3. Include in column (c) or (d), as appropriate, corrections of additions and retirements for the current or proceeding year.
4. Enclose in parentheses credit adjustments or plant accounts to indicate the negative effect of such accounts. 5. Classify Account 106 according to prescribed accounts, on an estimated basis if necessary, and include the entries in column (c). Also to be included in column (c) are entries for reversals of tentative distributions of prior year reported in column (b). Likewise, if the respondent has a significant amount of plant retirements which have not been classified to primary accounts at the end of the year, include in column (d) a tentative distribution of such retirements, on an estimated basis, with appropriate contra entries to the account for accumulated depreciation provision. Include also in column (d) reversals of tentative distribution of prior year classified retirements. Attach supplemental statements showing the account distributions of these tentative classifications in columns (c) and (d), including the reversals of the prior year's

Line No.	Account (a)	Balance at Beginning of Year (b)	Additions (c)
1	1. INTANGIBLE PLANT		
2	(301) Organization	5,339	-
3	(302) Franchises and Consents	-	-
4	(303) Miscellaneous Intangible Plant	-	-
5	TOTAL Intangible Plant (Enter total		
6	of lines 2, 3, and 4)	5,339	-
7	2. PRODUCTION PLANT		
8	A. Steam Production Plant		
9	(310) Land and Land Rights	-	-
10	(311) Structures and Improvements	-	-
11	(312) Boiler Plant Equipment	-	-
12	(313) Engines and Engine-Driven Generators	-	-
13	(314) Turbogenerator Units	-	-
14	(315) Accessory Electric Equipment	-	-
15	(316) Misc. Power Plant Equipment	-	-
16	TOTAL Steam Production Plant (Enter		
17	Total of lines 9 thru 16)	-	-
18	B. Nuclear Production Plant		
19	(320) Land and Land Rights	-	-
20	(321) Structures and Improvements	-	-
21	(322) Reactor Plant Equipment	-	-
22	(323) Turbogenerator Units	-	-
23	(324) Accessory Electric Equipment	-	-
24	(325) Misc. Power Plant Equipment	-	-
25	TOTAL Nuclear Production Plant (Enter		
26	Total of lines 19 thru 24)	-	-
27	C. Hydraulic Production Plant		
28	(330) Land and Land Rights	-	-
29	(331) Structures and Improvements	-	-
30	(332) Reservoirs, Dams, and Waterways	-	-
31	(333) Water Wheels, Turbines, & Generators	-	-
32	(334) Accessory Electric Equipment	-	-
33	(335) Misc. Power Plant Equipment	-	-
34	(336) Roads, Railroads, and Bridges	-	-
35	TOTAL Hydraulic Production Plant (Enter		
36	Total of lines 28 and 34)	-	-
37	D. Other Production Plant		
38	(340) Land and Land Rights	-	-
39	(341) Structures and Improvements	-	-
40	(342) Fuel Holders, Products and Accessories	-	-
41	(343) Prime Movers	-	-
42	(344) Generators	-	-
43	(345) Accessory Electric Equipment	-	-

*** AMOUNTS ARE VIRGINIA ONLY**

Name of Respondent KENTUCKY UTILITIES COMPANY*	This report is: (1) X An Original (2) ___ A Resubmission	Date of Report (Mo, Da, Yr)	Year of Report December 31, 2008

ELETRIC PLANT IN SERVICE (ACCOUNTS 101, 102, 103, AND 106)

tentative account distributions of these amounts. Careful observance of the above instructions and the texts of Accounts 101 and 106 will avoid serious omissions of the reported amount of respondent's plant actually in service at end of year. 6. Show in column (f) reclassifications or transfers within utility plant accounts. Include also in column (f) the additions or reductions of primary account classifications arising from distribution of amounts intially recorded in Account 102. In showing the clearance of Account 102, include in column (e) the amounts with respect to accumulated provision for depreciation, acquisition adjustments, etc., and show in column (f) only the offset to the debits or credits distributed in column (f) to primary account classifications. 7. For Account 399, state the nature and use of plant included in this account and, if substantial in amount, submit a supplementary statement showing subaccount classification of such plant conforming to the requirements of these pages. 8. For each amount comprising the reported balance and changes in Account 102, state journal entries have been filed with the Commission as required by the Uniform System of Accounts. Give also date of such filing.

Retirements (d)	Adjustments (e)	Transfers (f)	Balance at End of Year (g)		Line No.
					1
-	-	-	5,339	(301)	2
-	-	-	-	(302)	3
-	-	-	-	(303)	4
					5
-	-	-	5,339		6
					7
					8
-	-	-	-	(310)	9
-	-	-	-	(311)	10
-	-	-	-	(312)	11
-	-	-	-	(313)	12
-	-	-	-	(314)	13
-	-	-	-	(315)	14
-	-	-	-	(316)	15
					16
-	-	-	-		17
					18
-	-	-	-	(320)	19
-	-	-	-	(321)	20
-	-	-	-	(322)	21
-	-	-	-	(323)	22
-	-	-	-	(324)	23
-	-	-	-	(325)	24
					25
-	-	-	-		26
					27
-	-	-	-	(330)	28
-	-	-	-	(331)	29
-	-	-	-	(332)	30
-	-	-	-	(333)	31
-	-	-	-	(334)	32
-	-	-	-	(335)	33
-	-	-	-	(336)	34
					35
-	-	-	-		36
					37
-	-	-	-	(340)	38
-	-	-	-	(341)	39
-	-	-	-	(342)	40
-	-	-	-	(343)	41
-	-	-	-	(344)	42
-	-	-	-	(345)	43

*** AMOUNTS ARE VIRGINIA ONLY**

Name of Respondent KENTUCKY UTILITIES COMPANY*	This report is: (1) _X_ An Original (2) ___ A Resubmission	Date of Report (Mo, Da, Yr)	Year of Report December 31, 2008

ELECTRIC PLANT IN SERVICE (ACCOUNTS 101, 102, 103, AND 106) (Continued)

Line No.	Account (a)	Balance at Beginning of Year (b)	Additions (c)
44	(346) Misc Power Plant Equipment	-	-
45	TOTAL Other Production Plant (Enter		
46	Total of lines 38 thru 44)	-	-
47	TOTAL Production Plant (Enter Total		
48	of lines 17, 26, 36, and 46)	-	-
49	3. TRANSMISSION PLANT		
50	(350) Land and Land Rights	1,850,199	-
51	(352) Structures and Improvements	1,050,163	-
52	(353) Station Equipment	14,450,889	2,383,549
53	(354) Towers and Fixtures	6,714,334	-
54	(355) Poles and Fixtures	6,765,552	68,579
55	(356) Overhead Conductors and Devices	12,942,897	4,861
56	(357) Underground Conduit	-	-
57	(358) Underground Conductors and Devices	-	-
58	(359) Roads and Trails	-	-
59	TOTAL Transmission Plant (Enter Total		
60	of lines 50 thru 58)	43,774,034	2,456,989
61	4. DISTRIBUTION PLANT		
62	(360) Land and Land Rights	162,404	-
63	(361) Structures and Improvements	379,828	-
64	(362) Station Equipment	6,315,253	80,606
65	(363) Storage Battery Equipment	-	-
66	(364) Poles, Towers, and Fixtures	14,555,512	5,056,731
67	(365) Overhead Conductors and Devices	13,663,125	5,396,491
68	(366) Underground Conductors and Devices	-	-
69	(367) Underground Conductors and Devices	669,002	1,036,902
70	(368) Line Transformers	12,522,631	-
71	(369) Services	5,091,007	894,795
72	(370) Meters	3,616,919	-
73	(371) Installations on Customer Premises	868,638	-
74	(372) Leased Property on Customer Premises	-	-
75	(373) Street Lighting and Signal Systems	1,315,608	734,135
76	TOTAL Distribution Plant (Enter Total		
77	of lines 62 thru 75)	59,159,927	13,199,660
78	5. GENERAL PLANT		
79	(389) Land and Land Rights	80,602	-
80	(390) Structures and Improvements	596,264	-
81	(391) Office Furniture and Equipment	7,397	-
82	(392) Transportation Equipment	984,507	-
83	(393) Stores Equipment	8,103	-
84	(394) Tools, Shop and Garage Equipment	282,593	-
85	(395) Laboratory Equipment	34,640	-
86	(396) Power Operated Equipment	-	-
87	(397) Communication Equipment	550,541	
88	(398) Miscellaneous Equipment	9,128	-
89	SUBTOTAL (Enter Total of lines		
90	79 thru 88)	2,553,775	-
91	(399) Other Tangible Property	-	-
92	TOTAL General Plant (Enter Total		
93	of lines 90 and 91)	2,553,775	-
94	TOTAL (Accounts 101 and 106)	105,493,075	15,656,649
95	(102) Elec Plant Purchased (See Instr. 8)	-	-
96	(Less) (102) Elec Plant Sold (See Instr. 8)	-	-
97	(103) Experimental Plant Unclassified	-	-
98	TOTAL Electric Plant in Service	105,493,075	15,656,649

*** AMOUNTS ARE VIRGINIA ONLY**

Name of Respondent KENTUCKY UTILITIES COMPANY*	This report is: (1) X An Original (2) ___ A Resubmission	Date of Report (Mo, Da, Yr)	Year of Report December 31, 2008

ELETRIC PLANT IN SERVICE (ACCOUNTS 101, 102, 103, AND 106) (Continued)

Retirements (d)	Adjustments (e)	Transfers (f)	Balance at End of Year (g)		Line No.
-	-	-	-	(346)	44
					45
-	-	-	-		46
					47
-	-	-	-		48
					49
-	-	(30,847)	1,819,352	(350)	50
-	-	-	1,050,163	(352)	51
-	-	-	16,834,438	(353)	52
-	-	-	6,714,334	(354)	53
-	-	(933,604)	5,900,527	(355)	54
-	-	(990,118)	11,957,640	(356)	55
-	-	-	-	(357)	56
-	-	-	-	(358)	57
-	-	-	-	(359)	58
					59
-	-	(1,954,569)	44,276,454		60
					61
-	-	30,847	193,251	(360)	62
	-	-	379,828	(361)	63
170	-	(22,911)	6,372,778	(362)	64
-	-	-	-	(363)	65
-	-	769,581	20,381,824	(364)	66
-	-	990,822	20,050,438	(365)	67
-	-	-	-	(366)	68
-	-	-	1,705,904	(367)	69
13,200	-	-	12,509,431	(368)	70
-	-	-	5,985,802	(369)	71
-	-	-	3,616,919	(370)	72
-	-	-	868,638	(371)	73
-	-	-	-	(372)	74
-	-	-	2,049,743	(373)	75
					76
13,370	-	1,768,339	74,114,556		77
					78
-	-	-	80,602	(389)	79
-	-	-	596,264	(390)	80
-	-	-	7,397	(391)	81
-	-	-	984,507	(392)	82
-	-	-	8,103	(393)	83
-	-	-	282,593	(394)	84
-	-	-	34,640	(395)	85
-	-	-	-	(396)	86
-	-	-	550,541	(397)	87
	-	-	9,128	(398)	88
					89
-	-	-	2,553,775		90
-	-	-	-	(399)	91
					92
-	-	-	2,553,775		93
13,370	-	(186,230)	120,950,124		94
-	-	-	-	(102)	95
-	-	-	-		96
-	-	-	-	(103)	97
13,370	-	(186,230)	120,950,124		98

*** AMOUNTS ARE VIRGINIA ONLY**

Name of Respondent	This report is:	Date of Report	Year of Report
KENTUCKY UTILITIES COMPANY*	(1) X An Original (2) ___ A Resubmission	(Mo, Da, Yr)	December 31, 2008

ELECTRIC OPERATING REVENUES (Account 400)

1. Report below operating revenues for each prescribed account, and manufactured gas revenues in total.
2. Report number of customers, columns (f) and (g), on the basis of meters, in addition to the number of flat rate accounts; except that where separate meter readings are added for billing purposes, one customer should be counted for each group of meters added. The average number of customers means the average of twelve figures at the close of each month. 3. If increases or decreases from previous year (columns (c), (e), and (g)), are not derived from previously reported figures, explain any inconsistencies in a footnote.

Line No.	Title of Account (a)	VIRGINIA OPERATING REVENUES Amount for year (b)	VIRGINIA OPERATING REVENUES Amount for Previous Year (c)
1	Sales of Electricity		
2	(440) Residential Sales	26,739,734	25,973,321
3	(442) Commercial and Industrial Sales (A)		
4	Small (or Comm.) (See Instr. 4)(A)	12,807,985	12,565,714
5	Large (or Ind.) (See Instr. 4) (A)	11,971,638	11,858,956
6	(444) Public Street and Highway Lighting	276,493	250,996
7	(445) Other Sales to Public Authorities	5,060,646	4,729,314
8	(446) Sales to Railroads and Railways	-	-
9	(448) Interdepartmental Sales	-	-
10	TOTAL Sales to Ultimate Consumers	56,856,496	55,378,301
11	(447) Sales for Resale	-	-
12	TOTAL Sales of Electricity	56,856,496 (B)	55,378,301
13	(Less) (449.1) Provision for Rate Refunds		
14	TOTAL Revenues Net of Prov. For Refunds	56,856,496	55,378,301
15	Other Operating Revenues		
16	(450) Forfeited Discounts	-	-
17	(451) Miscellaneous Service Revenues	38,531	33,625
18	(453) Sales of Water and Water Power	-	-
19	(454) Rent from Electric Property	151,783	169,408
20	(455) Interdepartmental Rents	-	-
21	(456) Other Electric Revenues	-	781
22			
23			
24			
25			
26	TOTAL Other Operating Revenues	190,314	203,814
27	TOTAL Electric Operating Revenues	57,046,810	55,582,115

(A) Small Category includes Commercial Lighting and Power Accounts. Large category includes Industrial Lighting and Power and Mine Power Accounts. This is the same basis used for the previous year FERC Form No. 1.

(B) Includes $594,509 unbilled revenues.

* AMOUNTS ARE VIRGINIA ONLY

Name of Respondent KENTUCKY UTILITIES COMPANY*	This report is: (1) X An Original (2) ___ A Resubmission	Date of Report (Mo, Da, Yr)	Year of Report December 31, 2008

ELECTRIC OPERATING REVENUES (Account 400) (Continued)

4. Commercial and Industrial Sales, Account 442, may be classified according to the basis of classification (Small or Commercial, and Large or Industrial) regularly used by the respondent if such basis of classification is not generally greater than 1000 Kw of demand. (See Account 442 of the Uniform System of Accounts. Explain basis of classification in a footnote.) 5. See page 108, Important Changes During Year, for important new territory added and important rate increases or decreases. 6. For lines 2, 4, 5, and 6, see page 304 for amounts relating to unbilled revenue by accounts. 7. Include unmetered sales. Provide details of such sales in a footnote.

VIRGINIA MEGAWATT HOURS SOLD		VIRGINIA AVG. NO. CUSTOMERS PER MONTH		
Amount for Year (d)	Amount for Previous Year (e)	Number for Year (f)	Number for Previous Year (g)	Line No.
				1
418,645	414,751	25,342	25,321	2
				3
193,735	197,085	3,720	3,688	4
217,717	223,658	84	91	5
1,718	1,703	43	43	6
84,393	82,260	828	813	7
-	-	-	-	8
-	-	-	-	9
916,208	919,457	30,017	29,956	10
-	-	-	-	11
916,208 (c)	919,457	30,017	29,956	12
-	-	-	-	13
916,208	919,457	30,017	29,956	14

(c) Includes (1,916) MWH relating to unbilled revenues.

* AMOUNTS ARE VIRGINIA ONLY

Name of Respondent KENTUCKY UTILITIES COMPANY*	This report is: (1) _X_ An Original (2) ___ A Resubmission	Date of Report (Mo, Da, Yr)	Year of Report December 31, 2008

ELECTRIC OPERATING REVENUES (Account 400)

1. Report below operating revenues for each prescribed account, and manufactured gas revenues in total.
2. Report number of customers, columns (f) and (g), on the basis of meters, in addition to the number of flat rate accounts; except that where separate meter readings are added for billing purposes, one customer should be counted for each group of meters added. The average number of customers means the average of twelve figures at the close of each month. 3. If increases or decreases from previous year (columns (c), (e), and (g)), are not derived from previously reported figures, explain any inconsistencies in a footnote.

Line No.	Title of Account (a)	VIRGINIA JURISDICTIONAL OPERATING REVENUES Amount for year (b)	Amount for Previous Year (c)
1	Sales of Electricity		
2	(440) Residential Sales	26,739,734	25,973,321
3	(442) Commercial and Industrial Sales (A)		
4	Small (or Comm.) (See Instr. 4)(A)	12,807,985	12,565,714
5	Large (or Ind.) (See Instr. 4) (A)	11,971,638	11,858,956
6	(444) Public Street and Highway Lighting	5,030	5,085
7	(445) Other Sales to Public Authorities	3,882,077	3,604,259
8	(446) Sales to Railroads and Railways	-	-
9	(448) Interdepartmental Sales	-	-
10	TOTAL Sales to Ultimate Consumers	55,406,464	54,007,335
11	(447) Sales for Resale	-	-
12	TOTAL Sales of Electricity	55,406,464 (B)	54,007,335
13	(Less) (449.1) Provision for Rate Refunds	-	-
14	TOTAL Revenues Net of Prov. For Refunds	55,406,464	54,007,335
15	Other Operating Revenues		
16	(450) Forfeited Discounts	-	-
17	(451) Miscellaneous Service Revenues	38,199	33,339
18	(453) Sales of Water and Water Power	-	-
19	(454) Rent from Electric Property	62,130	91,492
20	(455) Interdepartmental Rents	-	-
21	(456) Other Electric Revenues	-	752
22			
23			
24			
25			
26	TOTAL Other Operating Revenues	100,329	125,583
27	TOTAL Electric Operating Revenues	55,506,793	54,132,918

(A) Small Category includes Commercial Lighting and Power Accounts. Large category includes Industrial Lighting and Power and Mine Power Accounts. This is the same basis used for the previous year FERC Form No. 1.

(B) Includes $ (2,577,151) unbilled revenues.

* AMOUNTS ARE VIRGINIA JURISDICTION ONLY

Name of Respondent KENTUCKY UTILITIES COMPANY*	This report is: (1) X An Original (2) ___ A Resubmission	Date of Report (Mo, Da, Yr)	Year of Report December 31, 2008

ELECTRIC OPERATING REVENUES (Account 400) (Continued)

4. Commercial and Industrial Sales, Account 442, may be classified according to the basis of classification (Small or Commercial, and Large or Industrial) regularly used by the respondent if such basis of classification is not generally greater than 1000 Kw of demand. (See Account 442 of the Uniform System of Accounts. Explain basis of classification in a footnote.) 5. See page 108, Important Changes During Year, for important new territory added and important rate increases of decreases. 6. For lines 2, 4, 5, and 6, see page 304 for amounts relating to unbilled revenue by accounts. 7. Include unmetered sales. Provide details of such sales in a footnote.

VIRGINIA JURISDICTIONAL MEGAWATT HOURS SOLD		VIRGINIA JURISDICTIONAL AVG. NO. CUSTOMERS PER MONTH		
Amount for Year (d)	Amount for Previous Year (e)	Number for Year (f)	Number for Previous Year (g)	Line No.
				1
418,644	414,751	25,342	25,321	2
				3
193,735	197,085	3,720	3,688	4
217,717	223,658	84	91	5
58	57	7	8	6
60,404	57,777	665	654	7
-	-	-	-	8
-	-	-	-	9
890,558	893,328	29,818	29,762	10
-	-	-	-	11
890,558 (c)	893,328	29,818	29,762	12
-	-	-	-	13
890,558	893,328	29,818	29,762	14

(c) Includes 2,329 MWH relating to unbilled revenues.

*** AMOUNTS ARE VIRGINIA JURISDICTION ONLY**

THIS FILING IS		
Item 1: [X] An Initial (Original) Submission	OR [ ]	Resubmission No. ____

Form 1 Approved
OMB No. 1902-0021
(Expires 2/29/2009)
Form 1-F Approved
OMB No. 1902-0029
(Expires 2/28/2009)
Form 3-Q Approved
OMB No. 1902-0205
(Expires 2/28/2009)

FERC FINANCIAL REPORT
FERC FORM No. 1: Annual Report of Major Electric Utilities, Licensees and Others and Supplemental Form 3-Q: Quarterly Financial Report

These reports are mandatory under the Federal Power Act, Sections 3, 4(a), 304 and 309, and 18 CFR 141.1 and 141.400. Failure to report may result in criminal fines, civil penalties and other sanctions as provided by law. The Federal Energy Regulatory Commission does not consider these reports to be of confidential nature

Exact Legal Name of Respondent (Company)	Year/Period of Report
Kentucky Utilities Company	End of 2008/Q4

PRICEWATERHOUSECOOPERS

PricewaterhouseCoopers LLP
500 West Main Street
Suite 1800
Louisville KY 40202-4264
Telephone (502) 589 6100
Facsimile (502) 585 7875

Report of Independent Auditors

To the Board of Directors and Management of Kentucky Utilities Company:

We have audited the accompanying balance sheets of Kentucky Utilities Company (the "Company") as of December 31, 2008 and 2007 and the related statements of income, retained earnings and cash flows for the years then ended, included on pages 110 through 123.44 of the accompanying Federal Energy Regulatory Commission Form 1. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with auditing standards generally accepted in the United States of America. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

As described in Note 1, these financial statements were prepared in accordance with the accounting requirements of the Federal Energy Regulatory Commission as set forth in its applicable Uniform System of Accounts and published accounting releases, which is a comprehensive basis of accounting other than generally accepted accounting principles in the United States of America.

In our opinion, the financial statements referred to above present fairly, in all material respects, the financial position of Kentucky Utilities Company as of December 31, 2008 and 2007, and the results of its operations and its cash flows for the years then ended in accordance with the accounting requirements of the Federal Energy Regulatory Commission as set forth in its applicable Uniform System of Accounts and published accounting releases.

This report is intended solely for the information and use of the board of directors and management of Kentucky Utilities Company and for filing with the Federal Energy Regulatory Commission and should not be used for any other purpose.

PricewaterhouseCoopers LLP

March 24, 2009

INSTRUCTIONS FOR FILING FERC FORM NOS. 1 and 3-Q

GENERAL INFORMATION

I. Purpose

FERC Form No. 1 (FERC Form 1) is an annual regulatory requirement for Major electric utilities, licensees and others (18 C.F.R. § 141.1). FERC Form No. 3-Q (FERC Form 3-Q)is a quarterly regulatory requirement which supplements the annual financial reporting requirement (18 C.F.R. § 141.400). These reports are designed to collect financial and operational information from electric utilities, licensees and others subject to the jurisdiction of the Federal Energy Regulatory Commission. These reports are also considered to be non-confidential public use forms.

II. Who Must Submit

Each Major electric utility, licensee, or other, as classified in the Commission's Uniform System of Accounts Prescribed for Public Utilities and Licensees Subject To the Provisions of The Federal Power Act (18 C.F.R. Part 101), must submit FERC Form 1 (18 C.F.R. § 141.1), and FERC Form 3-Q (18 C.F.R. § 141.400).

Note: Major means having, in each of the three previous calendar years, sales or transmission service that exceeds one of the following:

(1) one million megawatt hours of total annual sales,
(2) 100 megawatt hours of annual sales for resale,
(3) 500 megawatt hours of annual power exchanges delivered, or
(4) 500 megawatt hours of annual wheeling for others (deliveries plus losses).

III. What and Where to Submit

(a) Submit FERC Forms 1 and 3-Q electronically through the forms submission software. Retain one copy of each report for your files. Any electronic submission must be created by using the forms submission software provided free by the Commission at its web site: http://www.ferc.gov/docs-filing/eforms/form-1/elec-subm-soft.asp. The software is used to submit the electronic filing to the Commission via the Internet.

(b) The Corporate Officer Certification must be submitted electronically as part of the FERC Forms 1 and 3-Q filings.

(c) Submit immediately upon publication, by either eFiling or mail, two (2) copies to the Secretary of the Commission, the latest Annual Report to Stockholders. Unless eFiling the Annual Report to Stockholders, mail the stockholders report to the Secretary of the Commission at:

Secretary
Federal Energy Regulatory Commission
888 First Street, NE
Washington, DC 20426

(d) For the CPA Certification Statement, submit within 30 days after filing the FERC Form 1, a letter or report (not applicable to filers classified as Class C or Class D prior to January 1, 1984). The CPA Certification Statement can be either eFiled or mailed to the Secretary of the Commission at the address above.

The CPA Certification Statement should:

a) Attest to the conformity, in all material aspects, of the below listed (schedules and pages) with the Commission's applicable Uniform System of Accounts (including applicable notes relating thereto and the Chief Accountant's published accounting releases), and

b) Be signed by independent certified public accountants or an independent licensed public accountant certified or licensed by a regulatory authority of a State or other political subdivision of the U. S. (See 18 C.F.R. §§ 41.10-41.12 for specific qualifications.)

Reference Schedules	Pages
Comparative Balance Sheet	110-113
Statement of Income	114-117
Statement of Retained Earnings	118-119
Statement of Cash Flows	120-121
Notes to Financial Statements	122-123

e) The following format must be used for the CPA Certification Statement unless unusual circumstances or conditions, explained in the letter or report, demand that it be varied. Insert parenthetical phrases only when exceptions are reported.

"In connection with our regular examination of the financial statements of _____ for the year ended on which we have reported separately under date of ___________ , we have also reviewed schedules ___________________ of FERC Form No. 1 for the year filed with the Federal Energy Regulatory Commission, for conformity in all material respects with the requirements of the Federal Energy Regulatory Commission as set forth in its applicable Uniform System of Accounts and published accounting releases. Our review for this purpose included such tests of the accounting records and such other auditing procedures as we considered necessary in the circumstances.

Based on our review, in our opinion the accompanying schedules identified in the preceding paragraph (except as noted below) conform in all material respects with the accounting requirements of the Federal Energy Regulatory Commission as set forth in its applicable Uniform System of Accounts and published accounting releases."

The letter or report must state which, if any, of the pages above do not conform to the Commission's requirements. Describe the discrepancies that exist.

(f) Filers are encouraged to file their Annual Report to Stockholders, and the CPA Certification Statement using eFiling. To further that effort, new selections, "Annual Report to Stockholders," and "CPA Certification Statement" have been added to the dropdown "pick list" from which companies must choose when eFiling. Further instructions are found on the Commission's website at http://www.ferc.gov/help/how-to.asp.

(g) Federal, State and Local Governments and other authorized users may obtain additional blank copies of FERC Form 1 and 3-Q free of charge from http://www.ferc.gov/docs-filing/eforms/form-1/form-1.pdf and http://www.ferc.gov/docs-filing/eforms.asp#3Q-gas .

IV. When to Submit:

FERC Forms 1 and 3-Q must be filed by the following schedule:

a) FERC Form 1 for each year ending December 31 must be filed by April 18th of the following year (18 CFR § 141.1), and

b) FERC Form 3-Q for each calendar quarter must be filed within 60 days after the reporting quarter (18 C.F.R. § 141.400).

V. Where to Send Comments on Public Reporting Burden.

The public reporting burden for the FERC Form 1 collection of information is estimated to average 1,144 hours per response, including the time for reviewing instructions, searching existing data sources, gathering and maintaining the data-needed, and completing and reviewing the collection of information. The public reporting burden for the FERC Form 3-Q collection of information is estimated to average 150 hours per response.

Send comments regarding these burden estimates or any aspect of these collections of information, including suggestions for reducing burden, to the Federal Energy Regulatory Commission, 888 First Street NE, Washington, DC 20426 (Attention: Information Clearance Officer); and to the Office of Information and Regulatory Affairs, Office of Management and Budget, Washington, DC 20503 (Attention: Desk Officer for the Federal Energy Regulatory Commission). No person shall be subject to any penalty if any collection of information does not display a valid control number (44 U.S.C. § 3512 (a)).

GENERAL INSTRUCTIONS

I. Prepare this report in conformity with the Uniform System of Accounts (18 CFR Part 101) (USofA). Interpret all accounting words and phrases in accordance with the USofA.

II. Enter in whole numbers (dollars or MWH) only, except where otherwise noted. (Enter cents for averages and figures per unit where cents are important. The truncating of cents is allowed except on the four basic financial statements where rounding is required.) The amounts shown on all supporting pages must agree with the amounts entered on the statements that they support. When applying thresholds to determine significance for reporting purposes, use for balance sheet accounts the balances at the end of the current reporting period, and use for statement of income accounts the current year's year to date amounts.

III Complete each question fully and accurately, even if it has been answered in a previous report. Enter the word "None" where it truly and completely states the fact.

IV. For any page(s) that is not applicable to the respondent, omit the page(s) and enter "NA," "NONE," or "Not Applicable" in column (d) on the List of Schedules, pages 2 and 3.

V. Enter the month, day, and year for all dates. Use customary abbreviations. **The "Date of Report" included in the header of each page is to be completed only for resubmissions** (see VII. below).

VI. Generally, except for certain schedules, all numbers, whether they are expected to be debits or credits, must be reported as positive. Numbers having a sign that is different from the expected sign must be reported by enclosing the numbers in parentheses.

VII For any resubmissions, submit the electronic filing using the form submission software only. Please explain the reason for the resubmission in a footnote to the data field.

VIII. Do not make references to reports of previous periods/years or to other reports in lieu of required entries, except as specifically authorized.

IX. Wherever (schedule) pages refer to figures from a previous period/year, the figures reported must be based upon those shown by the report of the previous period/year, or an appropriate explanation given as to why the different figures were used.

Definitions for statistical classifications used for completing schedules for transmission system reporting are as follows:

FNS - Firm Network Transmission Service for Self. "Firm" means service that can not be interrupted for economic reasons and is intended to remain reliable even under adverse conditions. "Network Service" is Network Transmission Service as described in Order No. 888 and the Open Access Transmission Tariff. "Self" means the respondent.

FNO - Firm Network Service for Others. "Firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions. "Network Service" is Network Transmission Service as described in Order No. 888 and the Open Access Transmission Tariff.

LFP - for Long-Term Firm Point-to-Point Transmission Reservations. "Long-Term" means one year or longer and" firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions. "Point-to-Point Transmission Reservations" are described in Order No. 888 and the Open Access Transmission Tariff. For all transactions identified as LFP, provide in a footnote the termination date of the contract defined as the earliest date either buyer or seller can unilaterally cancel the contract.

OLF - Other Long-Term Firm Transmission Service. Report service provided under contracts which do not conform to the terms of the Open Access Transmission Tariff. "Long-Term" means one year or longer and "firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions. For all transactions identified as OLF, provide in a footnote the termination date of the contract defined as the earliest date either buyer or seller can unilaterally get out of the contract.

SFP - Short-Term Firm Point-to-Point Transmission Reservations. Use this classification for all firm point-to-point transmission reservations, where the duration of each period of reservation is less than one-year.

NF - Non-Firm Transmission Service, where firm means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions.

OS - Other Transmission Service. Use this classification only for those services which can not be placed in the above-mentioned classifications, such as all other service regardless of the length of the contract and service FERC Form. Describe the type of service in a footnote for each entry.

AD - Out-of-Period Adjustments. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting periods. Provide an explanation in a footnote for each adjustment.

DEFINITIONS

I. Commission Authorization (Comm. Auth.) -- The authorization of the Federal Energy Regulatory Commission, or any other Commission. Name the commission whose authorization was obtained and give date of the authorization.

II. Respondent -- The person, corporation, licensee, agency, authority, or other Legal entity or instrumentality in whose behalf the report is made.

EXCERPTS FROM THE LAW

Federal Power Act, 16 U.S.C. § 791a-825r

Sec. 3. The words defined in this section shall have the following meanings for purposes of this Act, to with:

(3) 'Corporation' means any corporation, joint-stock company, partnership, association, business trust, organized group of persons, whether incorporated or not, or a receiver or receivers, trustee or trustees of any of the foregoing. It shall not include 'municipalities, as hereinafter defined;

(4) 'Person' means an individual or a corporation;

(5) 'Licensee, means any person, State, or municipality Licensed under the provisions of section 4 of this Act, and any assignee or successor in interest thereof;

(7) 'municipality means a city, county, irrigation district, drainage district, or other political subdivision or agency of a State competent under the Laws thereof to carry and the business of developing, transmitting, unitizing, or distributing power; ......

(11) "project' means. a complete unit of improvement or development, consisting of a power house, all water conduits, all dams and appurtenant works and structures (including navigation structures) which are a part of said unit, and all storage, diverting, or fore bay reservoirs directly connected therewith, the primary line or lines transmitting power there from to the point of junction with the distribution system or with the interconnected primary transmission system, all miscellaneous structures used and useful in connection with said unit or any part thereof, and all water rights, rights-of-way, ditches, dams, reservoirs, Lands, or interest in Lands the use and occupancy of which are necessary or appropriate in the maintenance and operation of such unit;

"Sec. 4. The Commission is hereby authorized and empowered

(a) To make investigations and to collect and record data concerning the utilization of the water 'resources of any region to be developed, the water-power industry and its relation to other industries and to interstate or foreign commerce, and concerning the location, capacity, development -costs, and relation to markets of power sites; ... to the extent the Commission may deem necessary or useful for the purposes of this Act."

"Sec. 304. (a) Every Licensee and every public utility shall file with the Commission such annual and other periodic or special* reports as the Commission may be rules and regulations or other prescribe as necessary or appropriate to assist the Commission in the -proper administration of this Act. The Commission may prescribe the manner and FERC Form in which such reports salt be made, and require from such persons specific answers to all questions upon which the Commission may need information. The Commission may require that such reports shall include, among other things, full information as to assets and Liabilities, capitalization, net investment, and reduction thereof, gross receipts, interest due and paid, depreciation, and other reserves, cost of project and other facilities, cost of maintenance and operation of the project and other facilities, cost of renewals and replacement of the project works and other facilities, depreciation, generation, transmission, distribution, delivery, use, and sale of electric energy. The Commission may require any such person to make adequate provision for currently determining such costs and other facts. Such reports shall be made under oath unless the Commission otherwise specifies*.10

"Sec. 309. The Commission shall have power to perform any and all acts, and to prescribe, issue, make, and rescind such orders, rules and regulations as it may find necessary or appropriate to carry out the provisions of this Act. Among other things, such rules and regulations may define accounting, technical, and trade terms used in this Act; and may prescribe the FERC Form or FERC Forms of all statements, declarations, applications, and reports to be filed with the Commission, the information which they shall contain, and the time within which they shall be field..."

General Penalties

The Commission may assess up to $1 million per day per violation of its rules and regulations. *See* FPA § 316(a) (2005), 16 U.S.C. § 825o(a).

BLANK

FERC FORM NO. 1/3-Q:
REPORT OF MAJOR ELECTRIC UTILITIES, LICENSEES AND OTHER

IDENTIFICATION

01 Exact Legal Name of Respondent Kentucky Utilities Company	02 Year/Period of Report End of 2008/Q4
03 Previous Name and Date of Change *(if name changed during year)* / /	
04 Address of Principal Office at End of Period *(Street, City, State, Zip Code)* 220 West Main Street, P.O. Box 32010, Louisville, KY 40232	
05 Name of Contact Person Mimi Kelly	06 Title of Contact Person Mgr - Regulatory Acct & Reprt
07 Address of Contact Person *(Street, City, State, Zip Code)* P.O. Box 32010, Louisville, KY 40232	

08 Telephone of Contact Person, *Including Area Code* (502) 627-2482	09 This Report Is (1) [X] An Original (2) [ ] A Resubmission	10 Date of Report *(Mo, Da, Yr)* / /

ANNUAL CORPORATE OFFICER CERTIFICATION

The undersigned officer certifies that:

I have examined this report and to the best of my knowledge, information, and belief all statements of fact contained in this report are correct statements of the business affairs of the respondent and the financial statements, and other financial information contained in this report, conform in all material respects to the Uniform System of Accounts.

01 Name S. Bradford Rives	03 Signature S. Bradford Rives	04 Date Signed *(Mo, Da, Yr)* 03/24/2009
02 Title Chief Financial Officer		

Title 18, U.S.C. 1001 makes it a crime for any person to knowingly and willingly to make to any Agency or Department of the United States any false, fictitious or fraudulent statements as to any matter within its jurisdiction.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Utilities Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2008/Q4

LIST OF SCHEDULES (Electric Utility)

Enter in column (c) the terms "none," "not applicable," or "NA," as appropriate, where no information or amounts have been reported for certain pages. Omit pages where the respondents are "none," "not applicable," or "NA".

Line No.	Title of Schedule (a)	Reference Page No. (b)	Remarks (c)
1	General Information	101	
2	Control Over Respondent	102	
3	Corporations Controlled by Respondent	103	None
4	Officers	104	
5	Directors	105	
6	Important Changes During the Year	108-109	
7	Comparative Balance Sheet	110-113	
8	Statement of Income for the Year	114-117	
9	Statement of Retained Earnings for the Year	118-119	
10	Statement of Cash Flows	120-121	
11	Notes to Financial Statements	122-123	
12	Statement of Accum Comp Income, Comp Income, and Hedging Activities	122(a)(b)	None
13	Summary of Utility Plant & Accumulated Provisions for Dep, Amort & Dep	200-201	
14	Nuclear Fuel Materials	202-203	None
15	Electric Plant in Service	204-207	
16	Electric Plant Leased to Others	213	None
17	Electric Plant Held for Future Use	214	
18	Construction Work in Progress-Electric	216	
19	Accumulated Provision for Depreciation of Electric Utility Plant	219	
20	Investment of Subsidiary Companies	224-225	None
21	Materials and Supplies	227	
22	Allowances	228-229	
23	Extraordinary Property Losses	230	None
24	Unrecovered Plant and Regulatory Study Costs	230	None
25	Transmission Service and Generation Interconnection Study Costs	231	None
26	Other Regulatory Assets	232	
27	Miscellaneous Deferred Debits	233	
28	Accumulated Deferred Income Taxes	234	
29	Capital Stock	250-251	
30	Other Paid-in Capital	253	
31	Capital Stock Expense	254	
32	Long-Term Debt	256-257	
33	Reconciliation of Reported Net Income with Taxable Inc for Fed Inc Tax	261	
34	Taxes Accrued, Prepaid and Charged During the Year	262-263	
35	Accumulated Deferred Investment Tax Credits	266-267	
36	Other Deferred Credits	269	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Utilities Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2008/Q4

LIST OF SCHEDULES (Electric Utility) (continued)

Enter in column (c) the terms "none," "not applicable," or "NA," as appropriate, where no information or amounts have been reported for certain pages. Omit pages where the respondents are "none," "not applicable," or "NA".

Line No.	Title of Schedule (a)	Reference Page No. (b)	Remarks (c)
37	Accumulated Deferred Income Taxes-Accelerated Amortization Property	272-273	None
38	Accumulated Deferred Income Taxes-Other Property	274-275	
39	Accumulated Deferred Income Taxes-Other	276-277	
40	Other Regulatory Liabilities	278	
41	Electric Operating Revenues	300-301	
42	Sales of Electricity by Rate Schedules	304	
43	Sales for Resale	310-311	
44	Electric Operation and Maintenance Expenses	320-323	
45	Purchased Power	326-327	
46	Transmission of Electricity for Others	328-330	
47	Transmission of Electricity by ISO/RTOs	331	None
48	Transmission of Electricity by Others	332	
49	Miscellaneous General Expenses-Electric	335	
50	Depreciation and Amortization of Electric Plant	336-337	
51	Regulatory Commission Expenses	350-351	
52	Research, Development and Demonstration Activities	352-353	
53	Distribution of Salaries and Wages	354-355	
54	Common Utility Plant and Expenses	356	None
55	Amounts included in ISO/RTO Settlement Statements	397	
56	Purchase and Sale of Ancillary Services	398	
57	Monthly Transmission System Peak Load	400	
58	Monthly ISO/RTO Transmission System Peak Load	400a	None
59	Electric Energy Account	401	
60	Monthly Peaks and Output	401	
61	Steam Electric Generating Plant Statistics	402-403	
62	Hydroelectric Generating Plant Statistics	406-407	
63	Pumped Storage Generating Plant Statistics	408-409	None
64	Generating Plant Statistics Pages	410-411	None
65	Transmission Line Statistics Pages	422-423	
66	Transmission Lines Added During the Year	424-425	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Utilities Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2008/Q4

LIST OF SCHEDULES (Electric Utility) (continued)

Enter in column (c) the terms "none," "not applicable," or "NA," as appropriate, where no information or amounts have been reported for certain pages. Omit pages where the respondents are "none," "not applicable," or "NA".

Line No.	Title of Schedule (a)	Reference Page No. (b)	Remarks (c)
67	Substations	426-427	
68	Footnote Data	450	

Stockholders' Reports Check appropriate box:

[ ] Four copies will be submitted

[X] No annual report to stockholders is prepared

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Utilities Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2008/Q4

GENERAL INFORMATION

1. Provide name and title of officer having custody of the general corporate books of account and address of office where the general corporate books are kept, and address of office where any other corporate books of account are kept, if different from that where the general corporate books are kept.

S. Bradford Rives, Chief Financial Officer
220 West Main Street
Louisville, KY 40202

2. Provide the name of the State under the laws of which respondent is incorporated, and date of incorporation. If incorporated under a special law, give reference to such law. If not incorporated, state that fact and give the type of organization and the date organized.

Kentucky August 17, 1912
Virginia December 1, 1991

3. If at any time during the year the property of respondent was held by a receiver or trustee, give (a) name of receiver or trustee, (b) date such receiver or trustee took possession, (c) the authority by which the receivership or trusteeship was created, and (d) date when possession by receiver or trustee ceased.

Not Applicable

4. State the classes or utility and other services furnished by respondent during the year in each State in which the respondent operated.

Respondent furnishes electric services in Kentucky, Tennessee, and Virginia.

5. Have you engaged as the principal accountant to audit your financial statements an accountant who is not the principal accountant for your previous year's certified financial statements?

(1) [ ] Yes...Enter the date when such independent accountant was initially engaged:
(2) [X] No

CONTROL OVER RESPONDENT

1. If any corporation, business trust, or similar organization or a combination of such organizations jointly held control over the repondent at the end of the year, state name of controlling corporation or organization, manner in which control was held, and extent of control. If control was in a holding company organization, show the chain of ownership or control to the main parent company or organization. If control was held by a trustee(s), state name of trustee(s), name of beneficiary or beneficiearies for whom trust was maintained, and purpose of the trust.

Kentucky Utilities Company (KU) is a wholly-owned subsidiary of E.ON U.S. LLC. E.ON U.S. LLC. is an indirect wholly-owned subsidiary of E.ON AG, a German corporation, making KU an indirect wholly-owned subsidiary of E.ON AG.

BLANK

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Utilities Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2008/Q4

OFFICERS

1. Report below the name, title and salary for each executive officer whose salary is $50,000 or more. An "executive officer" of a respondent includes its president, secretary, treasurer, and vice president in charge of a principal business unit, division or function (such as sales, administration or finance), and any other person who performs similar policy making functions.
2. If a change was made during the year in the incumbent of any position, show name and total remuneration of the previous incumbent, and the date the change in incumbency was made.

Line No.	Title (a)	Name of Officer (b)	Salary for Year (c)
1	CURRENT OFFICERS AT DECEMBER 31, 2008		
2	Chairman of the Board, President and		
3	Chief Executive Officer	Victor A. Staffieri	
4	Executive Vice President, General Counsel,		
5	Corporate Secretary and Chief Compliance Officer	John R. McCall	
6	Chief Financial Officer	S. Bradford Rives	
7	Senior Vice President - Energy Delivery	Chris Hermann	
8	Senior Vice President - Human Resources	Paula H. Pottinger	
9	Senior Vice President - Energy Services	Paul W. Thompson	
10	Senior Vice President - Information Technology	Wendy C. Welsh	
11	Vice President - Federal Regulation and Policy	Michael S. Beer	
12	Vice President - State Regulation and Rates	Lonnie E. Bellar	
13	Vice President - Corporate Planning and Development	Kent W. Blake	
14	Vice President - Power Production	D. Ralph Bowling	
15	Vice President - Corporate Responsiblity		
16	and Community Affairs	Laura G. Douglas	
17	Vice President - Communications	R. W. Chip Keeling	
18	Vice President - Energy Delivery - Retail Business	John P. Malloy	
19	Vice President and Deputy General Counsel - Legal		
20	and Environmental Affairs	Dorothy E. O'Brien	
21	Vice President - External Affairs	George R. Siemens	
22	Vice President - Energy Marketing	David S. Sinclair	
23	Vice President - Energy Delivery - Distribution		
24	Operations	P. Greg Thomas	
25	Vice President - Transmission and Generation Services	John N. Voyles, Jr.	
26	Treasurer	Daniel K. Arbough	
27	Controller	Valerie L. Scott	
28			
29			
30			
31			
32			
33			
34			
35			
36			
37			
38			
39			
40			
41			
42			
43			
44			

Schedule Page: 104 Line No.: 1 Column: c

Salary information for all officers is on file in the office of the respondent.

Schedule Page: 104 Line No.: 14 Column: b

Effective June 16, 2008, D. Ralph Bowling was appointed Vice President – Power Production.

Schedule Page: 104 Line No.: 22 Column: b

Effective January 31, 2008, David S. Sinclair was appointed Vice President – Energy Marketing.

Schedule Page: 104 Line No.: 25 Column: b

Effective June 16, 2008, John N. Voyles, Jr. was appointed Vice President – Transmission and Generation Services.

BLANK

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Utilities Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2008/Q4

DIRECTORS

1. Report below the information called for concerning each director of the respondent who held office at any time during the year. Include in column (a), abbreviated titles of the directors who are officers of the respondent.
2. Designate members of the Executive Committee by a triple asterisk and the Chairman of the Executive Committee by a double asterisk.

Line No.	Name (and Title) of Director (a)	Principal Business Address (b)
1	CURRENT BOARD OF DIRECTORS AT DECEMBER 31, 2008	
2		
3	Victor A. Staffieri, Chairman of the Board, President	220 West Main Street, Louisville, KY 40202
4	and Chief Executive Officer	
5	John R. McCall, EVP General Counsel, Corporate	220 West Main Street, Louisville, KY 40202
6	Secretary and Chief Compliance Officer	
7	S. Bradford Rives, Chief Financial Officer	220 West Main Street, Louisville, KY 40202
8	Chris Hermann, SVP Energy Delivery	220 West Main Street, Louisville, KY 40202
9	Paul W. Thompson, SVP Energy Services	220 West Main Street, Louisville, KY 40202
10		
11		
12		
13		
14		
15		
16		
17		
18		
19		
20		
21		
22		
23		
24		
25		
26		
27		
28		
29		
30		
31		
32		
33		
34		
35		
36		
37		
38		
39		
40		
41		
42		
43		
44		
45		
46		
47		
48		

IMPORTANT CHANGES DURING THE QUARTER/YEAR

Give particulars (details) concerning the matters indicated below. Make the statements explicit and precise, and number them in accordance with the inquiries. Each inquiry should be answered. Enter "none," "not applicable," or "NA" where applicable. If information which answers an inquiry is given elsewhere in the report, make a reference to the schedule in which it appears.

1. Changes in and important additions to franchise rights: Describe the actual consideration given therefore and state from whom the franchise rights were acquired. If acquired without the payment of consideration, state that fact.
2. Acquisition of ownership in other companies by reorganization, merger, or consolidation with other companies: Give names of companies involved, particulars concerning the transactions, name of the Commission authorizing the transaction, and reference to Commission authorization.
3. Purchase or sale of an operating unit or system: Give a brief description of the property, and of the transactions relating thereto, and reference to Commission authorization, if any was required. Give date journal entries called for by the Uniform System of Accounts were submitted to the Commission.
4. Important leaseholds (other than leaseholds for natural gas lands) that have been acquired or given, assigned or surrendered: Give effective dates, lengths of terms, names of parties, rents, and other condition. State name of Commission authorizing lease and give reference to such authorization.
5. Important extension or reduction of transmission or distribution system: State territory added or relinquished and date operations began or ceased and give reference to Commission authorization, if any was required. State also the approximate number of customers added or lost and approximate annual revenues of each class of service. Each natural gas company must also state major new continuing sources of gas made available to it from purchases, development, purchase contract or otherwise, giving location and approximate total gas volumes available, period of contracts, and other parties to any such arrangements, etc.
6. Obligations incurred as a result of issuance of securities or assumption of liabilities or guarantees including issuance of short-term debt and commercial paper having a maturity of one year or less. Give reference to FERC or State Commission authorization, as appropriate, and the amount of obligation or guarantee.
7. Changes in articles of incorporation or amendments to charter: Explain the nature and purpose of such changes or amendments.
8. State the estimated annual effect and nature of any important wage scale changes during the year.
9. State briefly the status of any materially important legal proceedings pending at the end of the year, and the results of any such proceedings culminated during the year.
10. Describe briefly any materially important transactions of the respondent not disclosed elsewhere in this report in which an officer, director, security holder reported on Page 106, voting trustee, associated company or known associate of any of these persons was a party or in which any such person had a material interest.
11. (Reserved.)
12. If the important changes during the year relating to the respondent company appearing in the annual report to stockholders are applicable in every respect and furnish the data required by Instructions 1 to 11 above, such notes may be included on this page.
13. Describe fully any changes in officers, directors, major security holders and voting powers of the respondent that may have occurred during the reporting period.
14. In the event that the respondent participates in a cash management program(s) and its proprietary capital ratio is less than 30 percent please describe the significant events or transactions causing the proprietary capital ratio to be less than 30 percent, and the extent to which the respondent has amounts loaned or money advanced to its parent, subsidiary, or affiliated companies through a cash management program(s). Additionally, please describe plans, if any to regain at least a 30 percent proprietary ratio.

PAGE 108 INTENTIONALLY LEFT BLANK
SEE PAGE 109 FOR REQUIRED INFORMATION.

IMPORTANT CHANGES DURING THE QUARTER/YEAR (Continued)

1. None.

2. None.

3. None.

4. None of a material nature.

5. None of a material nature.

6. The Company had obtained authorization from the SEC under the Public Utility Holding Company Act of 1935 (PUHCA 1935) SEC File No. 70-10282 for the issuance of short-term debt up to $400 million through May 31, 2008. The Federal Power Act contained an exemption from FERC approval for securities issuances approved by the SEC under PUHCA 2005. In connection with the repeal of the PUHCA of 1935, the Company also received FERC authorization under the FPA Docket No. ES07-60-000 for up to $400 million in short-term debt through November 30, 2009. The Company's money pool balance decreased from $116 million at September 30, 2008 to $16 million at December 31, 2008. During the fourth quarter of 2008, the Company entered into a new long-term loan agreement with an affiliate for $75 million which matures in 2018, as authorized by the Kentucky Public Service Commission in its February 13, 2008 Order in Case No. 2007-00548, the Commonwealth of Virginia State Corporation Commission in its January 16, 2008 Order in Case No. PUE-2007-00118, and the Tennessee Regulatory Authority in its February 22, 2008 Order in Case No. 08-00009. In addition, the Company issued new bonds totaling $78 million with a maturity date of February 1, 2032 as authorized by the Kentucky Public Service Commission in its orders dated September 16, 2008 in Case No. 2008-00309 and June 17, 2008 in Case No. 2008-00132, the Commonwealth of Virginia State Corporation Commission in its orders dated August 29, 2008 in Case No. PUE-2008-00077 and June 19, 2008 in Case No. PUE 2008-00034, and the Tennessee Regulatory Authority in its orders dated September 15, 2008 in Case No. 08-00144 and July 15, 2008 in Case No. 08-00070. This transaction involved the refinancing of $60 million of previously issued bonds and $18 million of new funding.

7. None.

8. During the year, routine wage increases became effective for union employees in accordance with a collective bargaining agreement. Non-union employees received routine wage increases in accordance with annual salary reviews and job rotations.

9. See Notes 2 and 7 of Notes to Financial Statements.

10. None.

11. N/A

12. N/A

13. Martyn Gallus, formerly Senior Vice President, Energy Marketing, is serving in a position with an international affiliate, effective January 2008. Effective during January 2008, David S. Sinclair was appointed Vice President – Energy Marketing. Effective during June 2008, John N. Voyles, Jr. was appointed Vice President – Transmission and Generation Services. Additionally, during June 2008, D. Ralph Bowling was appointed Vice President – Power Production.

14. The Company is a participant in a cash pooling arrangement, but its proprietary capital ratio is above 30 percent.

Name of Respondent Kentucky Utilities Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2008/Q4

COMPARATIVE BALANCE SHEET (ASSETS AND OTHER DEBITS)

Line No.	Title of Account (a)	Ref. Page No. (b)	Current Year End of Quarter/Year Balance (c)	Prior Year End Balance 12/31 (d)
1	**UTILITY PLANT**			
2	Utility Plant (101-106, 114)	200-201	4,446,017,779	3,867,960,512
3	Construction Work in Progress (107)	200-201	1,176,440,172	1,071,388,626
4	TOTAL Utility Plant (Enter Total of lines 2 and 3)		5,622,457,951	4,939,349,138
5	(Less) Accum. Prov. for Depr. Amort. Depl. (108, 110, 111, 115)	200-201	2,052,492,161	1,931,454,524
6	Net Utility Plant (Enter Total of line 4 less 5)		3,569,965,790	3,007,894,614
7	Nuclear Fuel in Process of Ref., Conv.,Enrich., and Fab. (120.1)	202-203	0	0
8	Nuclear Fuel Materials and Assemblies-Stock Account (120.2)		0	0
9	Nuclear Fuel Assemblies in Reactor (120.3)		0	0
10	Spent Nuclear Fuel (120.4)		0	0
11	Nuclear Fuel Under Capital Leases (120.6)		0	0
12	(Less) Accum. Prov. for Amort. of Nucl. Fuel Assemblies (120.5)	202-203	0	0
13	Net Nuclear Fuel (Enter Total of lines 7-11 less 12)		0	0
14	Net Utility Plant (Enter Total of lines 6 and 13)		3,569,965,790	3,007,894,614
15	Utility Plant Adjustments (116)	122	0	0
16	Gas Stored Underground - Noncurrent (117)		0	0
17	**OTHER PROPERTY AND INVESTMENTS**			
18	Nonutility Property (121)		179,121	180,296
19	(Less) Accum. Prov. for Depr. and Amort. (122)		0	0
20	Investments in Associated Companies (123)		22,051,387	22,502,868
21	Investment in Subsidiary Companies (123.1)	224-225	0	0
22	(For Cost of Account 123.1, See Footnote Page 224, line 42)			
23	Noncurrent Portion of Allowances	228-229	0	0
24	Other Investments (124)		661,140	661,140
25	Sinking Funds (125)		0	0
26	Depreciation Fund (126)		0	0
27	Amortization Fund - Federal (127)		0	0
28	Other Special Funds (128)		5,997,831	5,915,884
29	Special Funds (Non Major Only) (129)		0	0
30	Long-Term Portion of Derivative Assets (175)		0	0
31	Long-Term Portion of Derivative Assets -- Hedges (176)		0	0
32	TOTAL Other Property and Investments (Lines 18-21 and 23-31)		28,889,479	29,260,188
33	**CURRENT AND ACCRUED ASSETS**			
34	Cash and Working Funds (Non-major Only) (130)		0	0
35	Cash (131)		2,413,346	321,021
36	Special Deposits (132-134)		9,510,009	10,985,556
37	Working Fund (135)		32,367	38,680
38	Temporary Cash Investments (136)		13	17,490
39	Notes Receivable (141)		0	0
40	Customer Accounts Receivable (142)		94,911,406	93,443,216
41	Other Accounts Receivable (143)		12,623,606	21,261,831
42	(Less) Accum. Prov. for Uncollectible Acct.-Credit (144)		2,878,505	1,939,209
43	Notes Receivable from Associated Companies (145)		0	0
44	Accounts Receivable from Assoc. Companies (146)		12,376,152	16,983,062
45	Fuel Stock (151)	227	72,708,035	41,770,628
46	Fuel Stock Expenses Undistributed (152)	227	0	0
47	Residuals (Elec) and Extracted Products (153)	227	0	0
48	Plant Materials and Operating Supplies (154)	227	29,561,689	27,370,026
49	Merchandise (155)	227	0	0
50	Other Materials and Supplies (156)	227	0	0
51	Nuclear Materials Held for Sale (157)	202-203/227	0	0
52	Allowances (158.1 and 158.2)	228-229	74,419	382,894

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Utilities Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2008/Q4

COMPARATIVE BALANCE SHEET (ASSETS AND OTHER DEBITS)(Continued)

Line No.	Title of Account (a)	Ref. Page No. (b)	Current Year End of Quarter/Year Balance (c)	Prior Year End Balance 12/31 (d)
53	(Less) Noncurrent Portion of Allowances		0	0
54	Stores Expense Undistributed (163)	227	6,202,308	6,454,808
55	Gas Stored Underground - Current (164.1)		0	0
56	Liquefied Natural Gas Stored and Held for Processing (164.2-164.3)		0	0
57	Prepayments (165)		5,833,903	5,293,879
58	Advances for Gas (166-167)		0	0
59	Interest and Dividends Receivable (171)		140,086	95,727
60	Rents Receivable (172)		0	0
61	Accrued Utility Revenues (173)		60,007,000	58,867,000
62	Miscellaneous Current and Accrued Assets (174)		0	16,145
63	Derivative Instrument Assets (175)		1,261,246	537,979
64	(Less) Long-Term Portion of Derivative Instrument Assets (175)		0	0
65	Derivative Instrument Assets - Hedges (176)		0	0
66	(Less) Long-Term Portion of Derivative Instrument Assets - Hedges (176		0	0
67	Total Current and Accrued Assets (Lines 34 through 66)		304,777,080	281,900,733
68	**DEFERRED DEBITS**			
69	Unamortized Debt Expenses (181)		4,671,224	7,281,131
70	Extraordinary Property Losses (182.1)	230	0	0
71	Unrecovered Plant and Regulatory Study Costs (182.2)	230	0	0
72	Other Regulatory Assets (182.3)	232	189,030,419	82,165,251
73	Prelim. Survey and Investigation Charges (Electric) (183)		4,492,923	1,667,653
74	Preliminary Natural Gas Survey and Investigation Charges 183.1)		0	0
75	Other Preliminary Survey and Investigation Charges (183.2)		0	0
76	Clearing Accounts (184)		621,641	-2,368,433
77	Temporary Facilities (185)		0	0
78	Miscellaneous Deferred Debits (186)	233	72,026,830	67,276,079
79	Def. Losses from Disposition of Utility Plt. (187)		0	0
80	Research, Devel. and Demonstration Expend. (188)	352-353	0	0
81	Unamortized Loss on Reaquired Debt (189)		13,356,279	10,173,667
82	Accumulated Deferred Income Taxes (190)	234	50,686,900	50,753,516
83	Unrecovered Purchased Gas Costs (191)		0	0
84	Total Deferred Debits (lines 69 through 83)		334,886,216	216,948,864
85	TOTAL ASSETS (lines 14-16, 32, 67, and 84)		4,238,518,565	3,536,004,399

BLANK

Schedule Page: 110 Line No.: 76 Column:

The negative balance resulted from a higher level of capital additions in 2007.

Name of Respondent	This Report is:	Date of Report (mo, da, yr)	Year/Period of Report
Kentucky Utilities Company	(1) [X] An Original (2) [ ] A Rresubmission	/ /	end of 2008/Q4

COMPARATIVE BALANCE SHEET (LIABILITIES AND OTHER CREDITS)

Line No.	Title of Account (a)	Ref. Page No. (b)	Current Year End of Quarter/Year Balance (c)	Prior Year End Balance 12/31 (d)
1	PROPRIETARY CAPITAL			
2	Common Stock Issued (201)	250-251	308,139,978	308,139,978
3	Preferred Stock Issued (204)	250-251	0	0
4	Capital Stock Subscribed (202, 205)	252	0	0
5	Stock Liability for Conversion (203, 206)	252	0	0
6	Premium on Capital Stock (207)	252	0	0
7	Other Paid-In Capital (208-211)	253	240,711,597	90,000,000
8	Installments Received on Capital Stock (212)	252	0	0
9	(Less) Discount on Capital Stock (213)	254	0	0
10	(Less) Capital Stock Expense (214)	254	321,289	321,289
11	Retained Earnings (215, 215.1, 216)	118-119	1,174,207,030	1,016,489,982
12	Unappropriated Undistributed Subsidiary Earnings (216.1)	118-119	20,755,587	21,207,068
13	(Less) Reaquired Capital Stock (217)	250-251	0	0
14	Noncorporate Proprietorship (Non-major only) (218)		0	0
15	Accumulated Other Comprehensive Income (219)	122(a)(b)	0	0
16	Total Proprietary Capital (lines 2 through 15)		1,743,492,903	1,435,515,739
17	LONG-TERM DEBT			
18	Bonds (221)	256-257	350,779,405	332,753,140
19	(Less) Reaquired Bonds (222)	256-257	0	0
20	Advances from Associated Companies (223)	256-257	1,181,000,000	931,000,000
21	Other Long-Term Debt (224)	256-257	0	0
22	Unamortized Premium on Long-Term Debt (225)		0	0
23	(Less) Unamortized Discount on Long-Term Debt-Debit (226)		0	0
24	Total Long-Term Debt (lines 18 through 23)		1,531,779,405	1,263,753,140
25	OTHER NONCURRENT LIABILITIES			
26	Obligations Under Capital Leases - Noncurrent (227)		0	0
27	Accumulated Provision for Property Insurance (228.1)		0	0
28	Accumulated Provision for Injuries and Damages (228.2)		2,592,340	3,098,519
29	Accumulated Provision for Pensions and Benefits (228.3)		192,048,802	87,925,008
30	Accumulated Miscellaneous Operating Provisions (228.4)		0	0
31	Accumulated Provision for Rate Refunds (229)		0	0
32	Long-Term Portion of Derivative Instrument Liabilities		0	0
33	Long-Term Portion of Derivative Instrument Liabilities - Hedges		0	0
34	Asset Retirement Obligations (230)		32,566,110	30,315,059
35	Total Other Noncurrent Liabilities (lines 26 through 34)		227,207,252	121,338,586
36	CURRENT AND ACCRUED LIABILITIES			
37	Notes Payable (231)		0	0
38	Accounts Payable (232)		162,946,460	161,858,433
39	Notes Payable to Associated Companies (233)		16,247,454	23,219,454
40	Accounts Payable to Associated Companies (234)		38,142,962	48,442,227
41	Customer Deposits (235)		21,057,049	19,573,318
42	Taxes Accrued (236)	262-263	8,558,560	4,089,209
43	Interest Accrued (237)		1,223,212	1,532,755
44	Dividends Declared (238)		0	0
45	Matured Long-Term Debt (239)		0	0

Name of Respondent	This Report is:	Date of Report (mo, da, yr)	Year/Period of Report
Kentucky Utilities Company	(1) [X] An Original (2) [ ] A Rresubmission	/ /	end of 2008/Q4

COMPARATIVE BALANCE SHEET (LIABILITIES AND OTHER CREDITS)(continued)

Line No.	Title of Account (a)	Ref. Page No. (b)	Current Year End of Quarter/Year Balance (c)	Prior Year End Balance 12/31 (d)
46	Matured Interest (240)		0	0
47	Tax Collections Payable (241)		3,824,617	3,515,457
48	Miscellaneous Current and Accrued Liabilities (242)		12,215,206	10,756,715
49	Obligations Under Capital Leases-Current (243)		0	0
50	Derivative Instrument Liabilities (244)		43,078	152,956
51	(Less) Long-Term Portion of Derivative Instrument Liabilities		0	0
52	Derivative Instrument Liabilities - Hedges (245)		0	0
53	(Less) Long-Term Portion of Derivative Instrument Liabilities-Hedges		0	0
54	Total Current and Accrued Liabilities (lines 37 through 53)		264,258,598	273,140,524
55	DEFERRED CREDITS			
56	Customer Advances for Construction (252)		2,430,316	2,803,337
57	Accumulated Deferred Investment Tax Credits (255)	266-267	79,951,702	54,999,112
58	Deferred Gains from Disposition of Utility Plant (256)		0	0
59	Other Deferred Credits (253)	269	21,709,079	13,436,144
60	Other Regulatory Liabilities (254)	278	40,483,283	37,721,036
61	Unamortized Gain on Reaquired Debt (257)		0	0
62	Accum. Deferred Income Taxes-Accel. Amort.(281)	272-277	0	0
63	Accum. Deferred Income Taxes-Other Property (282)		283,819,495	291,507,115
64	Accum. Deferred Income Taxes-Other (283)		43,386,532	41,789,666
65	Total Deferred Credits (lines 56 through 64)		471,780,407	442,256,410
66	TOTAL LIABILITIES AND STOCKHOLDER EQUITY (lines 16, 24, 35, 54 and 65)		4,238,518,565	3,536,004,399

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Utilities Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2008/Q4

STATEMENT OF INCOME

Quarterly
1. Enter in column (d) the balance for the reporting quarter and in column (e) the balance for the same three month period for the prior year.
2. Report in column (f) the quarter to date amounts for electric utility function; in column (h) the quarter to date amounts for gas utility, and in (j) the quarter to date amounts for other utility function for the current year quarter.
3. Report in column (g) the quarter to date amounts for electric utility function; in column (i) the quarter to date amounts for gas utility, and in (k) the quarter to date amounts for other utility function for the prior year quarter.
4. If additional columns are needed place them in a footnote.

Annual or Quarterly if applicable
5. Do not report fourth quarter data in columns (e) and (f)
6. Report amounts for accounts 412 and 413, Revenues and Expenses from Utility Plant Leased to Others, in another utility columnin a similar manner to a utility department. Spread the amount(s) over lines 2 thru 26 as appropriate. Include these amounts in columns (c) and (d) totals.
7. Report amounts in account 414, Other Utility Operating Income, in the same manner as accounts 412 and 413 above.
8. Report data for lines 8, 10 and 11 for Natural Gas companies using accounts 404.1, 404.2, 404.3, 407.1 and 407.2.

Line No.	Title of Account (a)	(Ref.) Page No. (b)	Total Current Year to Date Balance for Quarter/Year (c)	Total Prior Year to Date Balance for Quarter/Year (d)	Current 3 Months Ended Quarterly Only No 4th Quarter (e)	Prior 3 Months Ended Quarterly Only No 4th Quarter (f)
1	UTILITY OPERATING INCOME					
2	Operating Revenues (400)	300-301	1,404,042,053	1,272,548,899		
3	Operating Expenses					
4	Operation Expenses (401)	320-323	900,488,467	781,485,127		
5	Maintenance Expenses (402)	320-323	88,778,792	85,242,194		
6	Depreciation Expense (403)	336-337	130,780,795	115,064,736		
7	Depreciation Expense for Asset Retirement Costs (403.1)	336-337	334,214	199,429		
8	Amort. & Depl. of Utility Plant (404-405)	336-337	5,229,656	5,420,545		
9	Amort. of Utility Plant Acq. Adj. (406)	336-337				
10	Amort. Property Losses, Unrecov Plant and Regulatory Study Costs (407)					
11	Amort. of Conversion Expenses (407)					
12	Regulatory Debits (407.3)					
13	(Less) Regulatory Credits (407.4)		2,276,549	2,101,203		
14	Taxes Other Than Income Taxes (408.1)	262-263	20,661,094	18,439,077		
15	Income Taxes - Federal (409.1)	262-263	43,184,629	27,762,416		
16	- Other (409.1)	262-263	10,053,734	13,060,218		
17	Provision for Deferred Income Taxes (410.1)	234, 272-277	48,036,598	40,957,117		
18	(Less) Provision for Deferred Income Taxes-Cr. (411.1)	234, 272-277	61,388,975	47,805,346		
19	Investment Tax Credit Adj. - Net (411.4)	266	25,266,898	42,566,647		
20	(Less) Gains from Disp. of Utility Plant (411.6)					
21	Losses from Disp. of Utility Plant (411.7)					
22	(Less) Gains from Disposition of Allowances (411.8)		583,107	706,852		
23	Losses from Disposition of Allowances (411.9)					
24	Accretion Expense (411.10)		1,981,576	1,861,363		
25	TOTAL Utility Operating Expenses (Enter Total of lines 4 thru 24)		1,210,547,822	1,081,445,468		
26	Net Util Oper Inc (Enter Tot line 2 less 25) Carry to Pg117,line 27		193,494,231	191,103,431		

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Utilities Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2008/Q4

STATEMENT OF INCOME FOR THE YEAR (Continued)

9. Use page 122 for important notes regarding the statement of income for any account thereof.
10. Give concise explanations concerning unsettled rate proceedings where a contingency exists such that refunds of a material amount may need to be made to the utility's customers or which may result in material refund to the utility with respect to power or gas purchases. State for each year effected the gross revenues or costs to which the contingency relates and the tax effects together with an explanation of the major factors which affect the rights of the utility to retain such revenues or recover amounts paid with respect to power or gas purchases.
11 Give concise explanations concerning significant amounts of any refunds made or received during the year resulting from settlement of any rate proceeding affecting revenues received or costs incurred for power or gas purches, and a summary of the adjustments made to balance sheet, income, and expense accounts.
12. If any notes appearing in the report to stokholders are applicable to the Statement of Income, such notes may be included at page 122.
13. Enter on page 122 a concise explanation of only those changes in accounting methods made during the year which had an effect on net income, including the basis of allocations and apportionments from those used in the preceding year. Also, give the appropriate dollar effect of such changes.
14. Explain in a footnote if the previous year's/quarter's figures are different from that reported in prior reports.
15. If the columns are insufficient for reporting additional utility departments, supply the appropriate account titles report the information in a footnote to this schedule.

ELECTRIC UTILITY		GAS UTILITY		OTHER UTILITY		
Current Year to Date (in dollars) (g)	Previous Year to Date (in dollars) (h)	Current Year to Date (in dollars) (i)	Previous Year to Date (in dollars) (j)	Current Year to Date (in dollars) (k)	Previous Year to Date (in dollars) (l)	Line No.
						1
1,404,042,053	1,272,548,899					2
						3
900,488,467	781,485,127					4
88,778,792	85,242,194					5
130,780,795	115,064,736					6
334,214	199,429					7
5,229,656	5,420,545					8
						9
						10
						11
						12
2,276,549	2,101,203					13
20,661,094	18,439,077					14
43,184,629	27,762,416					15
10,053,734	13,060,218					16
48,036,598	40,957,117					17
61,388,975	47,805,346					18
25,266,898	42,566,647					19
						20
						21
583,107	706,852					22
						23
1,981,576	1,861,363					24
1,210,547,822	1,081,445,468					25
193,494,231	191,103,431					26

Name of Respondent Kentucky Utilities Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2008/Q4

STATEMENT OF INCOME FOR THE YEAR (continued)

Line No.	Title of Account (a)	(Ref.) Page No. (b)	TOTAL Current Year (c)	TOTAL Previous Year (d)	Current 3 Months Ended Quarterly Only No 4th Quarter (e)	Prior 3 Months Ended Quarterly Only No 4th Quarter (f)
27	Net Utility Operating Income (Carried forward from page 114)		193,494,231	191,103,431		
28	Other Income and Deductions					
29	Other Income					
30	Nonutilty Operating Income					
31	Revenues From Merchandising, Jobbing and Contract Work (415)					
32	(Less) Costs and Exp. of Merchandising, Job. & Contract Work (416)					
33	Revenues From Nonutility Operations (417)		1,355,192	1,542,843		
34	(Less) Expenses of Nonutility Operations (417.1)					
35	Nonoperating Rental Income (418)		25	6,560		
36	Equity in Earnings of Subsidiary Companies (418.1)	119	29,548,519	26,358,781		
37	Interest and Dividend Income (419)		1,483,141	2,954,429		
38	Allowance for Other Funds Used During Construction (419.1)		6,040,969	3,327,705		
39	Miscellaneous Nonoperating Income (421)		803,603	3,121,445		
40	Gain on Disposition of Property (421.1)		3,206	1,156,882		
41	TOTAL Other Income (Enter Total of lines 31 thru 40)		39,234,655	38,468,645		
42	Other Income Deductions					
43	Loss on Disposition of Property (421.2)			480,236		
44	Miscellaneous Amortization (425)	340				
45	Donations (426.1)	340	428,207	478,457		
46	Life Insurance (426.2)		-1,854,761	707,185		
47	Penalties (426.3)		-304,992	2,004,094		
48	Exp. for Certain Civic, Political & Related Activities (426.4)		769,559	965,125		
49	Other Deductions (426.5)		1,976,917	1,208,224		
50	TOTAL Other Income Deductions (Total of lines 43 thru 49)		1,014,930	5,843,321		
51	Taxes Applic. to Other Income and Deductions					
52	Taxes Other Than Income Taxes (408.2)	262-263	9,625	11,004		
53	Income Taxes-Federal (409.2)	262-263	2,295,770	88,667		
54	Income Taxes-Other (409.2)	262-263	224,373	-183,585		
55	Provision for Deferred Inc. Taxes (410.2)	234, 272-277	1,116,549	2,026,463		
56	(Less) Provision for Deferred Income Taxes-Cr. (411.2)	234, 272-277	534,443	504,303		
57	Investment Tax Credit Adj.-Net (411.5)					
58	(Less) Investment Tax Credits (420)		314,308	591,310		
59	TOTAL Taxes on Other Income and Deductions (Total of lines 52-58)		2,797,566	846,936		
60	Net Other Income and Deductions (Total of lines 41, 50, 59)		35,422,159	31,778,388		
61	Interest Charges					
62	Interest on Long-Term Debt (427)		12,778,173	13,677,837		
63	Amort. of Debt Disc. and Expense (428)		250,311	334,935		
64	Amortization of Loss on Reaquired Debt (428.1)		493,259	518,566		
65	(Less) Amort. of Premium on Debt-Credit (429)					
66	(Less) Amortization of Gain on Reaquired Debt-Credit (429.1)					
67	Interest on Debt to Assoc. Companies (430)	340	57,859,639	41,244,367		
68	Other Interest Expense (431)	340	2,317,909	1,099,347		
69	(Less) Allowance for Borrowed Funds Used During Construction-Cr. (432)		2,048,468	955,807		
70	Net Interest Charges (Total of lines 62 thru 69)		71,650,823	55,919,245		
71	Income Before Extraordinary Items (Total of lines 27, 60 and 70)		157,265,567	166,962,574		
72	Extraordinary Items					
73	Extraordinary Income (434)					
74	(Less) Extraordinary Deductions (435)					
75	Net Extraordinary Items (Total of line 73 less line 74)					
76	Income Taxes-Federal and Other (409.3)	262-263				
77	Extraordinary Items After Taxes (line 75 less line 76)					
78	Net Income (Total of line 71 and 77)		157,265,567	166,962,574		

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Utilities Company	(1) X An Original (2) _ A Resubmission	/ /	2008/Q4

FOOTNOTE DATA

Schedule Page: 114 Line No.: 46 Column: c

The 2008 balance represents the annual premium net of amortization of the cash value of the policy. The 2007 balance represents only the annual premium. In 2007, the amortization of the cash value of the policy was recorded to account 421003.

Schedule Page: 114 Line No.: 47 Column: c

The balance is a credit due to an adjustment of ($600,000) in 2008 to reduce a 2007 estimated penalty liability to actual.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Utilities Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2008/Q4

STATEMENT OF RETAINED EARNINGS

1. Do not report Lines 49-53 on the quarterly version.
2. Report all changes in appropriated retained earnings, unappropriated retained earnings, year to date, and unappropriated undistributed subsidiary earnings for the year.
3. Each credit and debit during the year should be identified as to the retained earnings account in which recorded (Accounts 433, 436 - 439 inclusive). Show the contra primary account affected in column (b)
4. State the purpose and amount of each reservation or appropriation of retained earnings.
5. List first account 439, Adjustments to Retained Earnings, reflecting adjustments to the opening balance of retained earnings. Follow by credit, then debit items in that order.
6. Show dividends for each class and series of capital stock.
7. Show separately the State and Federal income tax effect of items shown in account 439, Adjustments to Retained Earnings.
8. Explain in a footnote the basis for determining the amount reserved or appropriated. If such reservation or appropriation is to be recurrent, state the number and annual amounts to be reserved or appropriated as well as the totals eventually to be accumulated.
9. If any notes appearing in the report to stockholders are applicable to this statement, include them on pages 122-123.

Line No.	Item (a)	Contra Primary Account Affected (b)	Current Quarter/Year Year to Date Balance (c)	Previous Quarter/Year Year to Date Balance (d)
	UNAPPROPRIATED RETAINED EARNINGS (Account 216)			
1	Balance-Beginning of Period		1,016,489,982	854,131,028
2	Changes			
3	Adjustments to Retained Earnings (Account 439)			
4	FIN 48 Adjustment			355,161
5				
6				
7				
8				
9	TOTAL Credits to Retained Earnings (Acct. 439)			355,161
10				
11				
12				
13				
14				
15	TOTAL Debits to Retained Earnings (Acct. 439)			
16	Balance Transferred from Income (Account 433 less Account 418.1)		127,717,048	140,603,793
17	Appropriations of Retained Earnings (Acct. 436)			
18				
19				
20				
21				
22	TOTAL Appropriations of Retained Earnings (Acct. 436)			
23	Dividends Declared-Preferred Stock (Account 437)			
24				
25				
26				
27				
28				
29	TOTAL Dividends Declared-Preferred Stock (Acct. 437)			
30	Dividends Declared-Common Stock (Account 438)			
31				
32				
33				
34				
35				
36	TOTAL Dividends Declared-Common Stock (Acct. 438)			
37	Transfers from Acct 216.1, Unapprop. Undistrib. Subsidiary Earnings		30,000,000	21,400,000
38	Balance - End of Period (Total 1,9,15,16,22,29,36,37)		1,174,207,030	1,016,489,982
	APPROPRIATED RETAINED EARNINGS (Account 215)			

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Utilities Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2008/Q4

STATEMENT OF RETAINED EARNINGS

1. Do not report Lines 49-53 on the quarterly version.
2. Report all changes in appropriated retained earnings, unappropriated retained earnings, year to date, and unappropriated undistributed subsidiary earnings for the year.
3. Each credit and debit during the year should be identified as to the retained earnings account in which recorded (Accounts 433, 436 - 439 inclusive). Show the contra primary account affected in column (b)
4. State the purpose and amount of each reservation or appropriation of retained earnings.
5. List first account 439, Adjustments to Retained Earnings, reflecting adjustments to the opening balance of retained earnings. Follow by credit, then debit items in that order.
6. Show dividends for each class and series of capital stock.
7. Show separately the State and Federal income tax effect of items shown in account 439, Adjustments to Retained Earnings.
8. Explain in a footnote the basis for determining the amount reserved or appropriated. If such reservation or appropriation is to be recurrent, state the number and annual amounts to be reserved or appropriated as well as the totals eventually to be accumulated.
9. If any notes appearing in the report to stockholders are applicable to this statement, include them on pages 122-123.

Line No.	Item (a)	Contra Primary Account Affected (b)	Current Quarter/Year Year to Date Balance (c)	Previous Quarter/Year Year to Date Balance (d)
39				
40				
41				
42				
43				
44				
45	TOTAL Appropriated Retained Earnings (Account 215)			
	APPROP. RETAINED EARNINGS - AMORT. Reserve, Federal (Account 215.1)			
46	TOTAL Approp. Retained Earnings-Amort. Reserve, Federal (Acct. 215.1)			
47	TOTAL Approp. Retained Earnings (Acct. 215, 215.1) (Total 45,46)			
48	TOTAL Retained Earnings (Acct. 215, 215.1, 216) (Total 38, 47) (216.1)		1,174,207,030	1,016,489,982
	UNAPPROPRIATED UNDISTRIBUTED SUBSIDIARY EARNINGS (Account			
	Report only on an Annual Basis, no Quarterly			
49	Balance-Beginning of Year (Debit or Credit)		21,207,068	16,248,287
50	Equity in Earnings for Year (Credit) (Account 418.1)		29,548,519	26,358,781
51	(Less) Dividends Received (Debit)		30,000,000	21,400,000
52				
53	Balance-End of Year (Total lines 49 thru 52)		20,755,587	21,207,068

Name of Respondent Kentucky Utilities Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2008/Q4

STATEMENT OF CASH FLOWS

(1) Codes to be used:(a) Net Proceeds or Payments;(b)Bonds, debentures and other long-term debt; (c) Include commercial paper; and (d) Identify separately such items as investments, fixed assets, intangibles, etc.
(2) Information about noncash investing and financing activities must be provided in the Notes to the Financial statements. Also provide a reconciliation between "Cash and Cash Equivalents at End of Period" with related amounts on the Balance Sheet.
(3) Operating Activities - Other: Include gains and losses pertaining to operating activities only. Gains and losses pertaining to investing and financing activities should be reported in those activities. Show in the Notes to the Financials the amounts of interest paid (net of amount capitalized) and income taxes paid.
(4) Investing Activities: Include at Other (line 31) net cash outflow to acquire other companies. Provide a reconciliation of assets acquired with liabilities assumed in the Notes to the Financial Statements. Do not include on this statement the dollar amount of leases capitalized per the USofA General Instruction 20; instead provide a reconciliation of the dollar amount of leases capitalized with the plant cost.

Line No.	Description (See Instruction No. 1 for Explanation of Codes) (a)	Current Year to Date Quarter/Year (b)	Previous Year to Date Quarter/Year (c)
1	Net Cash Flow from Operating Activities:		
2	Net Income (Line 78(c) on page 117)	157,265,567	166,962,574
3	Noncash Charges (Credits) to Income:		
4	Depreciation and Depletion	131,115,009	115,264,165
5	Amortization of Plant	5,229,656	5,420,545
6			
7			
8	Deferred Income Taxes (Net)	-13,352,377	-1,604,551
9	Investment Tax Credit Adjustment (Net)	25,266,898	41,975,337
10	Net (Increase) Decrease in Receivables	11,538,195	-15,534,506
11	Net (Increase) Decrease in Inventory	-32,876,570	20,963,985
12	Net (Increase) Decrease in Allowances Inventory	308,475	1,287,644
13	Net Increase (Decrease) in Payables and Accrued Expenses	16,490,659	-77,626,160
14	Net (Increase) Decrease in Other Regulatory Assets	-106,865,168	32,851,592
15	Net Increase (Decrease) in Other Regulatory Liabilities	2,762,247	1,781,663
16	(Less) Allowance for Other Funds Used During Construction	8,089,437	4,283,511
17	(Less) Undistributed Earnings from Subsidiary Companies	-451,481	4,958,781
18	Other (provide details in footnote):	100,440,140	18,256,233
19	Change in Other Deferred Debits	-4,750,751	-3,188,788
20	Change in Other Deferred Credits	3,800,402	6,153,002
21			
22	Net Cash Provided by (Used in) Operating Activities (Total 2 thru 21)	288,734,426	303,720,443
23			
24	Cash Flows from Investment Activities:		
25	Construction and Acquisition of Plant (including land):		
26	Gross Additions to Utility Plant (less nuclear fuel)	-700,047,459	-744,355,547
27	Gross Additions to Nuclear Fuel		
28	Gross Additions to Common Utility Plant		
29	Gross Additions to Nonutility Plant		
30	(Less) Allowance for Other Funds Used During Construction	-8,089,437	-4,283,511
31	Other (provide details in footnote):		
32			
33			
34	Cash Outflows for Plant (Total of lines 26 thru 33)	-691,958,022	-740,072,036
35			
36	Acquisition of Other Noncurrent Assets (d)		
37	Proceeds from Disposal of Noncurrent Assets (d)		
38	Loss from Disposal of Fixed Assets (d)		-741,720
39	Investments in and Advances to Assoc. and Subsidiary Companies		
40	Contributions and Advances from Assoc. and Subsidiary Companies		
41	Disposition of Investments in (and Advances to)		
42	Associated and Subsidiary Companies		
43			
44	Purchase of Investment Securities (a)		
45	Proceeds from Sales of Investment Securities (a)		

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Utilities Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2008/Q4

STATEMENT OF CASH FLOWS

(1) Codes to be used:(a) Net Proceeds or Payments;(b)Bonds, debentures and other long-term debt; (c) Include commercial paper; and (d) Identify separately such items as investments, fixed assets, intangibles, etc.
(2) Information about noncash investing and financing activities must be provided in the Notes to the Financial statements. Also provide a reconciliation between "Cash and Cash Equivalents at End of Period" with related amounts on the Balance Sheet.
(3) Operating Activities - Other: Include gains and losses pertaining to operating activities only. Gains and losses pertaining to investing and financing activities should be reported in those activities. Show in the Notes to the Financials the amounts of interest paid (net of amount capitalized) and income taxes paid.
(4) Investing Activities: Include at Other (line 31) net cash outflow to acquire other companies. Provide a reconciliation of assets acquired with liabilities assumed in the Notes to the Financial Statements. Do not include on this statement the dollar amount of leases capitalized per the USofA General Instruction 20; instead provide a reconciliation of the dollar amount of leases capitalized with the plant cost.

Line No.	Description (See Instruction No. 1 for Explanation of Codes) (a)	Current Year to Date Quarter/Year (b)	Previous Year to Date Quarter/Year (c)
46	Loans Made or Purchased		
47	Collections on Loans		
48	Change in Long-Term Investments (d)	-81,947	-196,190
49	Net (Increase) Decrease in Receivables		
50	Net (Increase) Decrease in Inventory		
51	Net (Increase) Decrease in Allowances Held for Speculation		
52	Net Increase (Decrease) in Payables and Accrued Expenses		
53	Other (provide details in footnote):		
54	Change in Restricted Cash	1,475,547	11,821,428
55	Change in Long-Term Non-Hedging Derivative Liability	-833,145	
56	Net Cash Provided by (Used in) Investing Activities		
57	Total of lines 34 thru 55)	-691,397,567	-729,188,518
58			
59	Cash Flows from Financing Activities:		
60	Proceeds from Issuance of:		
61	Long-Term Debt (b)	326,631,129	526,750,683
62	Preferred Stock		
63	Common Stock		
64	Other (provide details in footnote):		
65	Change in Derivative Liabilities		-433,540
66	Net Increase in Short-Term Debt (c)		
67	Other (provide details in footnote):		
68	Reissuance of Reacquired Long-Term Debt (b)	62,900,000	
69	Retirement of Reacquired Long-Term Debt (b)	16,693,620	
70	Cash Provided by Outside Sources (Total 61 thru 69)	406,224,749	526,317,143
71			
72	Payments for Retirement of:		
73	Long-term Debt (b)	-59,921,140	-107,000,000
74	Preferred Stock		
75	Common Stock		
76	Other (provide details in footnote):		
77	Contributed Capital	145,000,000	75,000,000
78	Net Decrease in Short-Term Debt (c)	-6,972,000	-73,823,600
79	Payments for Reacquisition of Long-Term Debt (b)	-79,593,620	
80	Dividends on Preferred Stock		
81	Dividends on Common Stock		
82	Net Cash Provided by (Used in) Financing Activities		
83	(Total of lines 70 thru 81)	404,737,989	420,493,543
84			
85	Net Increase (Decrease) in Cash and Cash Equivalents		
86	(Total of lines 22,57 and 83)	2,074,848	-4,974,532
87			
88	Cash and Cash Equivalents at Beginning of Period	338,511	5,313,043
89			
90	Cash and Cash Equivalents at End of period	2,413,359	338,511

Schedule Page: 120 Line No.: 13 Column:

Restatement due to account reclassifications:

Previous Year to Date, as originally filed	$ (78,888,022)
Plus: Adjustment to Capital Expenditure Accrual	1,261,862
Restated Previous Year to Date	$ (77,626,160)

Schedule Page: 120 Line No.: 18 Column: b

Other operating cash flows:

Depreciation charged to balance sheet accounts	$ 726,899
Other changes in Net Utility Plant	(7,706,861)
Amortization of Debt Expenses and Loss on Bonds	743,571
Net increase in Prepayments	(540,025)
Net decrease in Land Options	16,145
Net increase in Preliminary Survey	(2,825,270)
Net increase in Clearing Accounts	(2,990,074)
Net decrease in Customer Advances for Construction	(373,020)
Net increase in Asset Retirement Obligations	2,251,051
Net increase in Provision for Postretirement Benefits	104,123,794
Deferred income taxes charged to balance sheet accounts	7,328,239
Investment tax credit charged to balance sheet accounts	(314,308)
Rounding	(1)
Total	$ 100,440,140

Schedule Page: 120 Line No.: 18 Column:

Other operating cash flows:

Depreciation charged to balance sheet accounts	$ 597,905
Other changes in Net Utility Plant	(2,308,564)
Amortization of Debt Expenses and Loss on Bonds	798,930
Net decrease in Prepayments	584,608
Net decrease in Derivative Assets	341,503
Net increase in Preliminary Survey	(1,373,637)
Net decrease in Clearing Accounts	5,121,080
Net increase in Customer Advances for Construction	830,470
Net increase in Asset Retirement Obligations	1,833,853
Net increase in Provision for Postretirement Benefits	11,474,924
Net adjustment to Retained Earnings (Effect of FIN 48)	355,161
Total	$ 18,256,233

Schedule Page: 120 Line No.: 26 Column:

Restatement due to account reclassifications:

Previous Year to Date, as originally filed	$ (743,093,685)
Less: Adjustment to Capital Expenditure Accrual	(1,261,862)
Restated Previous Year to Date	$ (744,355,547)

Schedule Page: 120 Line No.: 31 Column:

Restatement due to account reclassifications:

Previous Year to Date, as originally filed	$ (433,540)
Plus: Reclassification of Long-term Debt Mark-to-Market	433,540

Restated Previous Year to Date	$	-

Schedule Page: 120 Line No.: 48 Column: b

Other special funds

Schedule Page: 120 Line No.: 48 Column:

Change in Long-Term Investments:

Other Investments	$	15,000
Other Special Funds		(211,190)
Total Change in Long-Term Investments	$	(196,190)

Schedule Page: 120 Line No.: 65 Column:

Restatement due to account reclassifications:

Previous Year to Date, as originally filed	$	-
Less: Reclassification of Long-term Debt Mark-to-Market		(433,540)
Restated Previous Year to Date	$	(433,540)
Long-term Debt Mark-to-Market	$	(433,540)

In 2007, $53,000,000 of bonds were extinguished. This amount represents the fair value hedge adjustments on those bonds, as prescribed by SFAS No. 133, as amended.

Schedule Page: 120 Line No.: 90 Column: b

Cash and cash equivalents is comprised of the following amounts:

Cash (Acct 131)	$	2,413,346
Temporary Cash Investments (Acct 136)		13
Total Cash and Cash Equivalents at End of Period	$	2,413,359

Schedule Page: 120 Line No.: 90 Column:

Cash and cash equivalents is comprised of the following amounts:

Cash (Acct 131)	$	321,021
Temporary Cash Investments (Acct 136)		17,490
Total Cash and Cash Equivalents at End of Period	$	338,511

Name of Respondent	This Report Is:	Date of Report	Year/Period of Report
Kentucky Utilities Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2008/Q4

NOTES TO FINANCIAL STATEMENTS

1. Use the space below for important notes regarding the Balance Sheet, Statement of Income for the year, Statement of Retained Earnings for the year, and Statement of Cash Flows, or any account thereof. Classify the notes according to each basic statement, providing a subheading for each statement except where a note is applicable to more than one statement.
2. Furnish particulars (details) as to any significant contingent assets or liabilities existing at end of year, including a brief explanation of any action initiated by the Internal Revenue Service involving possible assessment of additional income taxes of material amount, or of a claim for refund of income taxes of a material amount initiated by the utility. Give also a brief explanation of any dividends in arrears on cumulative preferred stock.
3. For Account 116, Utility Plant Adjustments, explain the origin of such amount, debits and credits during the year, and plan of disposition contemplated, giving references to Cormmission orders or other authorizations respecting classification of amounts as plant adjustments and requirements as to disposition thereof.
4. Where Accounts 189, Unamortized Loss on Reacquired Debt, and 257, Unamortized Gain on Reacquired Debt, are not used, give an explanation, providing the rate treatment given these items. See General Instruction 17 of the Uniform System of Accounts.
5. Give a concise explanation of any retained earnings restrictions and state the amount of retained earnings affected by such restrictions.
6. If the notes to financial statements relating to the respondent company appearing in the annual report to the stockholders are applicable and furnish the data required by instructions above and on pages 114-121, such notes may be included herein.
7. For the 3Q disclosures, respondent must provide in the notes sufficient disclosures so as to make the interim information not misleading. Disclosures which would substantially duplicate the disclosures contained in the most recent FERC Annual Report may be omitted.
8. For the 3Q disclosures, the disclosures shall be provided where events subsequent to the end of the most recent year have occurred which have a material effect on the respondent. Respondent must include in the notes significant changes since the most recently completed year in such items as: accounting principles and practices; estimates inherent in the preparation of the financial statements; status of long-term contracts; capitalization including significant new borrowings or modifications of existing financing agreements; and changes resulting from business combinations or dispositions. However were material contingencies exist, the disclosure of such matters shall be provided even though a significant change since year end may not have occurred.
9. Finally, if the notes to the financial statements relating to the respondent appearing in the annual report to the stockholders are applicable and furnish the data required by the above instructions, such notes may be included herein.

PAGE 122 INTENTIONALLY LEFT BLANK
SEE PAGE 123 FOR REQUIRED INFORMATION.

INDEX OF ABBREVIATIONS

AG	Attorney General of Kentucky
ARO	Asset Retirement Obligation
BART	Best Available Retrofit Technology
CAIR	Clean Air Interstate Rule
CAMR	Clean Air Mercury Rule
CAVR	Clean Air Visibility Rule
CCN	Certificate of Public Convenience and Necessity
Clean Air Act	The Clean Air Act, as amended in 1990
CMRG	Carbon Management Research Group
Company	KU
CT	Combustion Turbines
DSM	Demand Side Management
ECR	Environmental Cost Recovery
EEI	Electric Energy, Inc.
E.ON	E.ON AG
E.ON U.S.	E.ON U.S. LLC (formerly LG&E Energy LLC and LG&E Energy Corp.)
E.ON U.S. Services	E.ON U.S. Services Inc. (formerly LG&E Energy Services Inc.)
EPA	U.S. Environmental Protection Agency
EPAct 2005	Energy Policy Act of 2005
FAC	Fuel Adjustment Clause
FASB	Financial Accounting Standards Board
FERC	Federal Energy Regulatory Commission
FGD	Flue Gas Desulfurization
Fidelia	Fidelia Corporation (an E.ON affiliate)
FIN	FASB Interpretation No.
GHG	Greenhouse Gas
IBEW	International Brotherhood of Electrical Workers
IMEA	Illinois Municipal Electric Agency
IMPA	Indiana Municipal Power Agency
IRP	Integrated Resource Plan
IRS	Internal Revenue Service
KCCS	Kentucky Consortium for Carbon Storage
KDAQ	Kentucky Division for Air Quality
Kentucky Commission	Kentucky Public Service Commission
KIUC	Kentucky Industrial Utility Consumers, Inc.
KU	Kentucky Utilities Company
Kwh	Kilowatt hours
LG&E	Louisville Gas and Electric Company
LG&E Energy	LG&E Energy LLC (now E.ON U.S. LLC)
MISO	Midwest Independent Transmission System Operator, Inc.
MMBtu	Million British thermal units
Moody's	Moody's Investor Services, Inc.

Mw	Megawatts
Mwh	Megawatt hours
NAAQS	National Ambient Air Quality Standards
NERC	North American Electric Reliability Corporation
NOV	Notice of Violation
NOx	Nitrogen Oxide
OMU	Owensboro Municipal Utilities
OVEC	Ohio Valley Electric Corporation
PCB	Polychlorinated Biphenyl
PUHCA 2005	Public Utility Holding Company Act of 2005
RRO	Regional Reliability Organization
RSG	Revenue Sufficiency Guarantee
S&P	Standard & Poor's Rating Services
SCR	Selective Catalytic Reduction
SERC	SERC Reliability Corporation
SFAS	Statement of Financial Accounting Standards
SIP	State Implementation Plan
SO_2	Sulfur Dioxide
TC2	Trimble County Unit 2
VDT	Value Delivery Team Process
Virginia Commission	Virginia State Corporation Commission

Note 1 - Summary of Significant Accounting Policies

KU, incorporated in Kentucky in 1912 and in Virginia in 1991, is a regulated public utility engaged in the generation, transmission, distribution and sale of electric energy in Kentucky, Virginia and Tennessee. KU provides electric service to approximately 508,000 customers in 77 counties in central, southeastern and western Kentucky, to approximately 30,000 customers in 5 counties in southwestern Virginia and 5 customers in Tennessee. KU's service area covers approximately 6,600 square miles. Approximately 99% of the electricity generated by KU is produced by its coal-fired electric generating stations. The remainder is generated by a hydroelectric power plant and natural gas and oil fueled CTs. In Virginia, KU operates under the name Old Dominion Power Company. KU also sells wholesale electric energy to 12 municipalities.

KU is a wholly-owned subsidiary of E.ON U.S., an indirect wholly-owned subsidiary of E.ON, a German corporation. KU's affiliate, LG&E, is a regulated public utility engaged in the generation, transmission, distribution and sale of electric energy and the distribution and sale of natural gas in Kentucky.

Certain reclassification entries have been made to the previous years' financial statements to conform to the 2008 presentation with no impact on net assets, liabilities and capitalization or previously reported net income and net cash flows.

Presentation. The accompanying financial statements are prepared on the regulatory basis of accounting in accordance with the requirements of the FERC, which is a comprehensive basis of accounting other than

Generally Accepted Accounting Principles ("GAAP"). The significant differences between GAAP and FERC reporting are as follows:

- Restricted cash is recorded in cash on the balance sheet for FERC reporting and presented as a separate line item for GAAP statements;
- Certain costs of removal obligations are recorded in accumulated depreciation for FERC reporting and recorded in regulatory liabilities for GAAP reporting;
- Long-term and short-term bonds are recorded in total in the long-term debt section for FERC reporting and are presented separately in current liabilities for the short-term portion and in long-term debt for the long-term portion for GAAP reporting; and
- Deferred taxes are shown gross for FERC reporting in the balance sheet (a deferred asset and a deferred liability are recorded), for GAAP reporting the deferred taxes are netted together and recorded as a liability.

Regulatory Accounting. KU is subject to SFAS No. 71, under which regulatory assets are created based on expected recovery from customers in future rates to defer costs that would otherwise be charged to expense. Likewise, regulatory liabilities are created based on expected return to customers in future rates to defer credits that would otherwise be reflected as income, or, in the case of costs of removal, are created to match long-term future obligations arising from the current use of assets. The accounting for regulatory assets and liabilities is based on specific ratemaking decisions or precedent for each item as prescribed by the FERC, the Kentucky Commission or the Virginia Commission. See Note 2, Rates and Regulatory Matters, for additional detail regarding regulatory assets and liabilities.

Cash and Cash Equivalents. KU considers all highly liquid investments with an original maturity of three months or less to be cash equivalents.

Restricted Cash. Proceeds from bond issuances for environmental equipment (primarily related to the installation of FGDs) are held in trust pending expenditure for qualifying assets.

Allowance for Doubtful Accounts. The allowance for doubtful accounts is based on the ratio of the amounts charged-off during the last twelve months to the retail revenues billed over the same period multiplied by the retail revenues billed over the last four months. Accounts with no payment activity are charged-off after four months, although collection efforts continue thereafter.

Materials and Supplies. Fuel and other materials and supplies inventories are accounted for using the average-cost method. Emission allowances are included in other materials and supplies and are not currently traded by KU. At December 31, 2008 and 2007, the emission allowances inventory was less than $1 million.

Other Property and Investments. Other property and investments on the balance sheets consists of KU's investment in EEI, economic development loans provided to various communities in the service territory, KU's investment in OVEC, funds related to the long-term purchased power contract with OMU and non-utility plant.

Although KU holds investment interests in OVEC and EEI, it is not the primary beneficiary, therefore, neither are consolidated into the Company's financial statements. KU and 11 other electric utilities are participating owners of OVEC, located in Piketon, Ohio. OVEC owns and operates two coal-fired power plants, Kyger Creek

Station in Ohio and Clifty Creek Station in Indiana. Pursuant to current contractual agreements, KU's share of OVEC's output is 2.5%, approximately 55 Mw of generation capacity.

As of December 31, 2008 and 2007, KU's investment in OVEC totaled less than $1 million and is accounted for under the cost method of accounting. The direct exposure to loss as a result of its involvement with OVEC is generally limited to the value of its investment. In the event of the inability of OVEC to fulfill its power provision requirements, KU anticipates substituting such power supply with either owned generation or market purchases and believes it would generally recover associated incremental costs through regulatory rate mechanisms. See Note 9, Commitments and Contingencies, for further discussion of developments regarding KU's ownership interests and power purchase rights.

KU owns 20% of the common stock of EEI, which owns and operates a 1,162-Mw generating station in southern Illinois. KU's investment in EEI is accounted for under the equity method of accounting and, as of December 31, 2008 and 2007, totaled $22 million and $23 million, respectively. KU's direct exposure to loss as a result of its involvement with EEI is generally limited to the value of its investment.

Utility Plant. Utility plant is stated at original cost, which includes payroll-related costs such as taxes, fringe benefits and administrative and general costs. Construction work in progress has been included in the rate base for determining retail customer rates in Kentucky. KU has not recorded a significant allowance for funds used during construction.

The cost of plant retired or disposed of in the normal course of business is deducted from plant accounts and such cost is charged to the reserve for depreciation. When complete operating units are disposed of, appropriate adjustments are made to the reserve for depreciation and gains and losses, if any, are recognized.

Depreciation and Amortization. Depreciation is provided on the straight-line method over the estimated service lives of depreciable plant. The amounts provided were approximately 3.0% in 2008 and 3.2% in 2007 of average depreciable plant. Of the amount provided for depreciation at December 31, 2008 and 2007, approximately 0.5% was related to the retirement, removal and disposal costs of long lived assets.

Unamortized Debt Expense. Debt expense is capitalized in deferred debits and amortized using the straight line method, which approximates the effective interest method, over the lives of the related bond issues.

Income Taxes. Income taxes are accounted for under SFAS No. 109, *Accounting for Income Taxes* and FIN 48, *Accounting for Uncertainty in Income Taxes, an Interpretation of SFAS No. 109*. In accordance with these statements, deferred tax assets and liabilities are recognized for the future tax consequences attributable to differences between the financial statement carrying amounts of existing assets and liabilities and their respective tax bases, as measured by enacted tax rates that are expected to be in effect in the periods when the deferred tax assets and liabilities are expected to be settled or realized. Significant judgment is required in determining the provision for income taxes, and there are transactions for which the ultimate tax outcome is uncertain. FIN 48 prescribes a recognition threshold and measurement attribute for the financial statement recognition and measurement of a tax position taken or expected to be taken in a tax return. Uncertain tax positions are analyzed periodically and adjustments are made when events occur to warrant a change. See Note 6, Income Taxes.

Deferred Income Taxes. Deferred income taxes are recognized at currently enacted tax rates for all material temporary differences between the financial reporting and income tax bases of assets and liabilities.

Investment Tax Credits. The EPAct 2005 added Section 48A to the Internal Revenue Code, which provides for an investment tax credit to promote the commercialization of advanced coal technologies that will generate electricity in an environmentally responsible manner. KU and LG&E received an investment tax credit related to TC2. See Note 6, Income Taxes. Investment tax credits prior to 2006 resulted from provisions of the tax law that permitted a reduction of KU's tax liability based on credits for construction expenditures. Deferred investment tax credits are being amortized to income over the estimated lives of the related property that gave rise to the credits.

Revenue Recognition. Revenues are recorded based on service rendered to customers through month-end. KU accrues an estimate for unbilled revenues from each meter reading date to the end of the accounting period based on allocating the daily system net deliveries between billed volumes and unbilled volumes. The allocation is based on a daily ratio of the number of meter reading cycles remaining in the month to the total number of meter reading cycles in each month. Each day's ratio is then multiplied by each day's system net deliveries to determine an estimated billed and unbilled volume for each day of the accounting period. The unbilled revenue estimates included in accounts receivable were $60 million and $59 million at December 31, 2008 and 2007, respectively.

Fuel Costs. The cost of fuel for generation is charged to expense as used.

Management's Use of Estimates. The preparation of financial statements in conformity with generally accepted accounting principles requires management to make estimates and assumptions that affect the reported assets and liabilities and disclosure of contingent items at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. Accrued liabilities, including legal and environmental, are recorded when they are probable and estimable. Actual results could differ from those estimates.

Recent Accounting Pronouncements. The following are recent accounting pronouncements affecting KU:

<u>SFAS No. 161</u>

In March 2008, the FASB issued SFAS No. 161, *Disclosures about Derivative Instruments and Hedging Activities, an amendment of FASB Statement No. 133,* which is effective for fiscal years, and interim periods within those fiscal years, beginning on or after November 15, 2008. The objective of this statement is to enhance the current disclosure framework in SFAS No. 133, *Accounting for Derivative Instruments and Hedging Activities, as amended.* The adoption of SFAS No. 161 will have no impact on KU's statements of operations, financial position and cash flows, however, additional disclosures relating to derivatives will be required beginning in the first quarter of 2009.

SFAS No. 160

In December 2007, the FASB issued SFAS No. 160, *Noncontrolling Interests in Consolidated Financial Statements,* which is effective for fiscal years, and interim periods within those fiscal years, beginning on or after December 15, 2008. The objective of this statement is to improve the relevance, comparability and transparency of financial information in a reporting entity's consolidated financial statements. The Company expects the adoption of SFAS No. 160 to have no impact on its statements of operations, financial position and cash flows.

SFAS No. 159

In February 2007, the FASB issued SFAS No. 159, *The Fair Value Option for Financial Assets and Financial Liabilities -- Including an Amendment of FASB Statement No. 115.* SFAS No. 159 permits entities to choose to measure many financial instruments and certain other assets and liabilities at fair value on an instrument-by-instrument basis (the fair value option). Unrealized gains and losses on items for which the fair value option has been elected are to be recognized in earnings at each subsequent reporting date. SFAS No. 159 was adopted effective January 1, 2008 and the Company elected not to fair value its eligible financial assets and liabilities.

SFAS No. 157

In September 2006, the FASB issued SFAS No. 157, *Fair Value Measurements*, which, except as described below, is effective for fiscal years beginning after November 15, 2007. This statement defines fair value, establishes a framework for measuring fair value in generally accepted accounting principles and expands disclosures about fair value measurements. SFAS No. 157 does not expand the application of fair value accounting to new circumstances. In February 2008, the FASB issued FASB Staff Position 157-2, *Effective Date of FASB Statement No. 157,* which delays the effective date of SFAS No. 157 for all nonfinancial assets and liabilities, except those that are recognized or disclosed at fair value in the financial statements on a recurring basis (at least annually), to fiscal years beginning after November 15, 2008, and interim periods within those fiscal years. All other amendments related to SFAS No. 157 have been evaluated and have no impact on the Company's financial statements. SFAS No. 157 was adopted effective January 1, 2008, except as it applies to those nonfinancial assets and liabilities, and had no impact on the statements of operations, financial position and cash flows, however, additional disclosures relating to its financial derivatives and cash collateral on derivatives, as required, are now provided. Per FASB Staff Position 157-2, fair value accounting for all nonrecurring fair value measurements of nonfinancial assets and liabilities will be adopted effective January 1, 2009.

Note 2 - Rates and Regulatory Matters

The Company is subject to the jurisdiction of the Kentucky Commission, the Virginia Commission, the Tennessee Regulatory Authority and the FERC in virtually all matters related to electric utility regulation, and as such, its accounting is subject to SFAS No. 71. Given its position in the marketplace and the status of regulation in Kentucky and Virginia, there are no plans or intentions to discontinue the application of SFAS No. 71.

Kentucky Rate Case

In July 2008, KU filed an application with the Kentucky Commission requesting an increase in base electric rates. In conjunction with the filing of the application for a change in base rates, based on previous Orders by the Kentucky Commission approving settlement agreements among all interested parties, the VDT surcredit terminated in August 2008. In January 2009, KU, the AG, KIUC and all other parties to the rate case filed a settlement agreement with the Kentucky Commission, under which KU's base electric rates will decrease by $9 million annually. An Order approving the settlement agreement was received in February 2009. The new rates were implemented effective February 6, 2009, at which time the merger surcredit terminated.

The VDT surcredit originated in December 2001, when the Kentucky Commission issued an Order approving a settlement agreement allowing KU to set up a regulatory asset of $54 million for workforce reduction costs and begin amortizing it over a five-year period starting in April 2001. The Order also provided for a surcredit to be included on customers' bills representing 40% of the annual savings derived from this initiative. For periods beginning January 1, 2006, the VDT surcredit had increased to $4 million per year.

In February 2006, KU and all parties to the proceeding reached a unanimous settlement agreement on the future ratemaking treatment of the VDT surcredit. Under the terms of the settlement agreement, the VDT surcredit continued at its current level until such time as KU filed for a change in base rates. The Kentucky Commission issued an Order in March 2006, approving the settlement agreement. In accordance with the Order, the VDT surcredit terminated in August 2008, the first billing month after the July 2008 filing for a change in base rates.

The merger surcredit originated as part of the LG&E Energy merger with KU Energy Corporation in 1998. It was based on estimated non-fuel savings over a ten-year period following the merger. Costs to achieve these savings were deferred and amortized over a five-year period pursuant to regulatory orders. In approving the merger, the Kentucky Commission adopted KU's proposal to reduce its retail customers' bills based on one-half of the estimated merger-related savings, net of deferred and amortized amounts, over a five-year period. These savings were provided in the form of a surcredit mechanism on customers' bills. In October 2003, the Kentucky Commission issued an Order approving a unanimous settlement agreement reached with all parties to the case in which the merger surcredit of $18 million per year would remain in place for another five-year term beginning July 1, 2003, and KU would file a plan for the merger surcredit six months before its expiration.

In December 2007, KU submitted its plan to allow the merger surcredit to terminate as scheduled on June 30, 2008. In June 2008, the Kentucky Commission issued an Order approving a unanimous settlement agreement reached with all parties to the case which provided for a reduction in the merger surcredit to approximately $6 million for a 7-month period beginning July 2008, termination of the merger surcredit when new base rates went into effect on or after January 31, 2009, and that the annual merger surcredit be continued at an annual rate of $12 million thereafter should the Company not file for a change in base rates. In accordance with the Order, the merger surcredit was terminated effective February 6, 2009, with the implementation of new base rates.

FERC Wholesale Rate Case

In September 2008, KU filed an application with the FERC for increases in base electric rates applicable to wholesale power sales contracts or interchange agreements involving, collectively, twelve Kentucky municipalities. The application requests a shift from current, all-in stated unit charge rates to an unbundled and formula rate. The revised rates represent varying increases of 6% to 7% from current charges and include a change from the all-in stated applicable return on equity of 11.8%. The proceeding involves data requests and hearings before the FERC, as well as data requests and filings by intervenors. In November 2008, the FERC issued an Order to suspend rates until May 1, 2009, at which time the applied for rates will become effective, subject to potential refund or adjustment commencing in October 2009, based upon the outcome of the proceedings. Concurrently with the progress of the FERC rate proceedings, KU and the municipal customers have commenced structured settlement negotiations overseen by the FERC.

Regulatory Assets and Liabilities

The following regulatory assets and liabilities were included in the balance sheets as of December 31:

(in millions)	2008	2007
ARO	$ 28	$ 24
MISO exit	19	20
Unamortized loss on bonds	13	10
FAC	9	17
ECR	20	11
Hurricane Ike	2	-
Other	5	4
Subtotal	96	86
Pension and postretirement benefits	127	28
Total regulatory assets	$ 223	$ 114
Deferred income taxes – net	$ 16	$ 22
Other	20	10
Total regulatory liabilities	$ 36	$ 32

KU does not currently earn a rate of return on the FAC regulatory asset, which is a separate recovery mechanism with recovery within twelve months. No return is earned on the pension and postretirement benefits regulatory asset that represents the changes in funded status of the plans. KU will recover this asset through the pension expense included in the calculation of base rates with the Kentucky Commission and will seek recovery of this asset in future proceedings with the Virginia Commission. No return is currently earned on the ARO asset. This regulatory asset will be offset against the associated regulatory liability, ARO asset and ARO liability at the time the underlying asset is retired. The MISO exit amount represents the costs relating to the withdrawal from MISO membership. Approval for the recovery of this asset was received from the Kentucky Commission as part of the 2008 base rate case and KU will seek recovery of this asset in future proceedings with the Virginia Commission. KU currently earns a rate of return on remaining regulatory assets, including other regulatory assets comprised of VDT costs (2007 only), merger surcredit and deferred storm costs. Other regulatory assets also include KCCS funding (see CMRG and KCCS Contributions below), FERC jurisdictional pension expense and rate case expenses. KU will seek recovery of the KCCS funding in the next base rate case and received approval for the recovery of the rate case expenses as part of the 2008 base rate case. Other regulatory liabilities include DSM and MISO costs included in base rates that will be netted against costs of withdrawing from the MISO as part of the settlement agreement in the 2008 base rate case.

ARO. A summary of KU's net ARO assets, regulatory assets, ARO liabilities, regulatory liabilities and cost of removal established under FIN 47, *Accounting for Conditional Asset Retirement Obligations, an Interpretation of SFAS No. 143,* and SFAS No. 143, *Accounting for Asset Retirement Obligations,* follows:

	ARO Net Assets	ARO Liabilities	Regulatory Assets	Regulatory Liabilities	Accumulated Cost of Removal	Cost of Removal Depreciation
As of December 31, 2006	$ 5	$ (28)	$ 22	$ (2)	$ 2	$ 1
ARO accretion	-	(2)	2	-	-	-
As of December 31, 2007	5	(30)	24	(2)	2	1
ARO accretion	-	(2)	2	-	-	-
Removal cost reclass	-	-	2	(2)	-	-
As of December 31, 2008	$ 5	$ (32)	$ 28	$ (4)	$ 2	$ 1

Pursuant to regulatory treatment prescribed under SFAS No. 71, an offsetting regulatory credit was recorded in depreciation and amortization in the income statement of $2 million in 2008 and 2007 for the ARO accretion and depreciation expense. KU AROs are primarily related to the final retirement of assets associated with generating units. For assets associated with AROs, the removal cost accrued through depreciation under regulatory accounting is established as a regulatory liability pursuant to regulatory treatment prescribed under SFAS No. 71. There were no FIN 47 net asset additions during 2008 or 2007. For the years ended December 31, 2008 and 2007, KU recorded less than $1 million of depreciation expense related to the cost of removal of ARO related assets. An offsetting regulatory liability was established pursuant to regulatory treatment prescribed under SFAS No. 71.

KU transmission and distribution lines largely operate under perpetual property easement agreements which do not generally require restoration upon removal of the property. Therefore, under SFAS No. 143, no material asset retirement obligations are recorded for transmission and distribution assets.

MISO. Following receipt of applicable FERC, Kentucky Commission and other regulatory orders, KU withdrew from the MISO effective September 1, 2006. Specific proceedings regarding the costs and benefits of the MISO and exit matters had been underway since July 2003. Since the exit from the MISO, KU has been operating under a FERC-approved open access-transmission tariff. KU now contracts with the Tennessee Valley Authority to act as its transmission Reliability Coordinator and Southwest Power Pool, Inc. to function as its Independent Transmission Organization, pursuant to FERC requirements.

KU and the MISO have agreed upon overall calculation methods for the contractual exit fee to be paid by the Company following its withdrawal. In October 2006, the Company paid $20 million to the MISO pursuant to an invoice regarding the exit fee and made related FERC compliance filings. The Company's payment of this exit fee amount was with reservation of its rights to contest the amount, or components thereof, following a continuing review of its calculation and supporting documentation. KU and the MISO resolved their dispute regarding the calculation of the exit fee and, in November 2007, filed an application with the FERC for approval of a recalculation agreement. In March 2008, the FERC approved the parties' recalculation of the exit fee, and the approved agreement provided KU with an immediate recovery of $1 million and an estimated $3 million over the next seven years for credits realized from other payments the MISO will receive, plus interest. In accordance with Kentucky Commission Orders approving the MISO exit, KU has established a regulatory asset for the exit fee, subject to adjustment for possible future MISO credits, and a regulatory liability for certain revenues associated with former MISO administrative charges, which continue to be collected via base rates. The approved base rate case settlement provided for MISO Schedule 10 expenses collected through base rates from May 1, 2008 to February 6, 2009, and any future adjustments to the MISO exit fee, to be established as a regulatory liability until the amounts can be amortized in future base rate cases.

In November 2008, the FERC issued Orders in industry-wide proceedings relating to MISO RSG calculation and resettlement procedures. RSG charges are amounts assessed to various participants active in the MISO trading market which generally seek to compensate for uneconomic generation dispatch due to regional transmission or power market operational considerations, with some customer classes eligible for payments, while others may bear charges. The FERC Orders approved two requests for significantly altered formulas and principles, each of which the FERC applied differently to calculate RSG charges for various historical and future periods. KU and other parties have requested rehearing and a delay in any collection of RSG amounts. During January and February 2009, the FERC issued a deficiency letter in the proceeding relating to one prior Order, which delays collection of applicable RSG resettlements by the MISO pending further proceedings. Further developments in the RSG proceeding are expected to occur during 2009. Due to the numerous participants, complex principles at issue and changes from prior precedents, KU cannot predict the ultimate outcome of this matter. Based upon the recent FERC Orders, KU established a reserve during the fourth quarter of 2008, of less than $1 million relating to potential RSG resettlement costs for the period ended December 31, 2008.

Unamortized Loss on Bonds. The costs of early extinguishment of debt, including call premiums, legal and other expenses, and any unamortized balance of debt expense are amortized using the straight line method, which approximates the effective interest method, over the life of either the replacement debt (in the case of refinancing) or the original life of the extinguished debt.

FAC. KU's retail rates contain an FAC, whereby increases and decreases in the cost of fuel for generation are reflected in the rates charged to retail customers. The FAC allows the Company to adjust customers' accounts for the difference between the fuel cost component of base rates and the actual fuel cost, including transportation costs. Refunds to customers occur if the actual costs are below the embedded cost component. Additional charges to customers occur if the actual costs exceed the embedded cost component. The amount of the regulatory asset or liability is the amount that has been under- or over-recovered due to timing or adjustments to the mechanism.

The Kentucky Commission requires public hearings at six-month intervals to examine past fuel adjustments, and at two-year intervals to review past operations of the fuel clause and transfer of the then current fuel adjustment charge or credit to the base charges.

In January 2009, the Kentucky Commission initiated a routine examination of KU's FAC for the two-year period November 1, 2006 through October 31, 2008. A public hearing is scheduled in March 2009. An order is anticipated in the second quarter of 2009.

In August 2008, the Kentucky Commission initiated a routine examination of KU's FAC for the six-month period November 1, 2007 through April 30, 2008. The Kentucky Commission issued an Order in January 2009, approving the charges and credits billed through the FAC during the review period.

In January 2008, the Kentucky Commission initiated a routine examination of KU's FAC for the six-month period May 1, 2007 through October 31, 2007. The Kentucky Commission issued an Order in June 2008, approving the charges and credits billed through the FAC during the review period.

In August 2007, the Kentucky Commission initiated a routine examination of KU's FAC for the six-month period of November 1, 2006 through April 30, 2007. The Kentucky Commission issued an Order in January 2008, approving the charges and credits billed through the FAC during the review period.

In December 2006, the Kentucky Commission initiated its periodic two-year review of KU's past operations of the fuel clause and transfer of fuel costs from the FAC to base rates for November 1, 2004 through October 31, 2006. In March 2007, the KIUC challenged KU's recovery of approximately $5 million in aggregate fuel costs KU incurred during a period prior to its exit from the MISO and requested the Kentucky Commission disallow this amount. A public hearing was held in May 2007. In October 2007, the Kentucky Commission issued its Order approving the calculation and application of KU's FAC charges and fuel procurement practices and indicated that KU was in compliance with the provisions of Administrative Regulation 807 KAR 5:5056. The Kentucky Commission further approved KU's recommendation for the transfer of fuel cost from the FAC to base rates. In November 2007, the KIUC filed a petition for rehearing, claiming the Kentucky Commission misinterpreted the KIUC's arguments in the proceeding. In the same month, the Kentucky Commission issued an Order denying the KIUC's request for rehearing. An appeal was not filed by the KIUC.

In January 2003, the Kentucky Commission reviewed KU's FAC for the six-month period ended October 31, 2001. The Kentucky Commission ordered KU to reduce its fuel costs for purposes of calculating its FAC by less than $1 million. At issue was the purchase of approximately 102,000 tons of coal from Western Kentucky Energy Corp., a non-regulated affiliate, for use at KU's Ghent facility. The Kentucky Commission further ordered that an independent audit be conducted to examine operational and management aspects of both KU's and LG&E's fuel procurement functions. The final report's recommendations, issued in February 2004, related to documentation and process improvements. Management Audit Action Plans were agreed upon by KU and the Kentucky Commission Staff in the second quarter of 2004, and resulted in Audit Progress Reports being filed by KU with the Kentucky Commission. In February 2007, the Kentucky Commission staff indicated that KU fully complied with all audit recommendations and that no further reports are required.

KU also employs an FAC mechanism for Virginia customers using an average fuel cost factor based primarily on projected fuel costs. The factor may be adjusted annually for over- or under-collections of fuel costs from the prior year. In February 2008, KU filed an application with the Virginia Commission seeking approval of a decrease in its fuel cost factor applicable during the billing period, April 2008 through March 2009. The Virginia Commission allowed the new rates to be in effect for the April 2008 customer billings. In April 2008, the Virginia Commission Staff recommended a change to the fuel factor KU filed in its application, to which KU has agreed. Following a public hearing and an Order in May 2008, the recommended change became effective in June 2008, resulting in a decrease of 0.482 cents/kwh from the factor in effect for the April 2007 through March 2008 period.

ECR. Kentucky law permits KU to recover the costs of complying with the Federal Clean Air Act, including a return of operating expenses, and a return of and on capital invested, through the ECR mechanism. The amount of the regulatory asset or liability is the amount that has been under- or over-recovered due to timing or adjustments to the mechanism.

In February 2009, the Kentucky Commission approved a settlement agreement in the rate case which provides for an authorized return on equity applicable to the ECR mechanism of 10.63% effective with the March 2009 expense month filing, which represents a slight increase over the current 10.50%.

In January 2009, the Kentucky Commission initiated a six-month review for the period ending October 31, 2008, of KU's environmental surcharge. An order is anticipated in the second quarter of 2009.

In June 2008, the Kentucky Commission initiated two six-month reviews for periods ending October 31, 2007 and April 30, 2008, of KU's environmental surcharge. The Kentucky Commission issued an Order in August 2008, approving the charges and credits billed through the ECR during the review period and the rate of return on capital.

In October 2007, KU met with the Kentucky Commission and other interested parties to discuss the status of the Ghent Unit 2 SCR construction. KU informed the Kentucky Commission that construction of the Ghent Unit 2 SCR was not going to commence before the CCN expired in December 2007, due to a change in the economics for the project. The CCN expired in December 2007, and KU has delayed construction of the Ghent Unit 2 SCR.

In September 2007, the Kentucky Commission initiated six-month and two-year reviews for periods ending October 31, 2006 and April 30, 2007, respectively, of KU's environmental surcharge. The Kentucky Commission issued a final Order in March 2008, approving the charges and credits billed through the ECR during the review periods, as well as approving billing adjustments, roll-in adjustments to base rates, revisions to the monthly surcharge filing and the rates of return on capital.

Hurricane Ike. In September 2008, high winds from the remnants of Hurricane Ike passed through the service territory causing significant outages and system damage. In October 2008, KU filed an application with the Kentucky Commission requesting approval to establish a regulatory asset, and defer for future recovery, approximately $3 million of expenses related to the storm restoration. In December 2008, the Kentucky Commission issued an Order allowing the Company to establish a regulatory asset of up to $3 million based on its actual costs for storm damages and service restoration due to Hurricane Ike.

FERC Jurisdictional Pension Costs. Pension costs of $3 million incurred by the Company allocated to its FERC jurisdictional ratepayers. The Company will seek recovery of this asset in the next FERC rate proceeding.

Rate Case Expenses. KU incurred $1 million in expenses related to the development and support of the 2008 Kentucky base rate case. The Kentucky Commission approved the establishment of a regulatory asset for these expenses and authorized amortization over three years beginning in March 2009.

CMRG and KCCS Contributions. In July 2008, KU and LG&E, along with Duke Energy Kentucky, Inc. and Kentucky Power Company, filed an application with the Kentucky Commission requesting approval to establish regulatory assets related to contributions to the CMRG for the development of technologies for reducing carbon dioxide emissions and the KCCS to study the feasibility of geologic storage of carbon dioxide. The filing companies proposed that these contributions be treated as regulatory assets to be deferred until recovery is provided in the next base rate case of each company, at which time the regulatory assets will be amortized over the life of each project: four years with respect to the KCCS and ten years with respect to the CMRG. KU and LG&E jointly agreed to provide less than $2 million over two years to the KCCS and up to $2 million over ten years to the CMRG. In October 2008, an Order approving the establishment of the requested regulatory assets was received and KU will seek rate recovery in the Company's next base rate case.

Deferred Storm Costs. Based on an Order from the Kentucky Commission in June 2004, KU reclassified from maintenance expense to a regulatory asset, $4 million related to costs not reimbursed from the 2003 ice storm. These costs will be amortized through June 2009. KU earns a return of these amortized costs, which are included in jurisdictional operating expenses.

Pension and Postretirement Benefits. KU adopted SFAS No. 158, *Employers' Accounting for Defined Benefit Pension and Other Postretirement Plans,* in 2006. This statement requires employers to recognize the over-funded or under-funded status of a defined benefit pension and postretirement plan as an asset or liability in the balance sheet and to recognize through other comprehensive income the changes in the funded status in the year in which the changes occur. Under SFAS No. 71, KU can defer recoverable costs that would otherwise be charged to expense or equity by non-regulated entities. Current rate recovery in Kentucky and Virginia is based on SFAS No. 87, *Employers' Accounting for Pensions,* and SFAS No. 106, *Employers' Accounting for Postretirement Benefits Other than Pensions,* both of which were amended by SFAS No. 158. Regulators have been clear and consistent with their historical treatment of such rate recovery, therefore, the Company has recorded a regulatory asset representing the change in funded status of the pension and postretirement plans that is expected to be recovered. The regulatory asset will be adjusted annually as prior service cost and actuarial gains and losses are recognized in net periodic benefit cost.

Deferred Income Taxes – Net. These regulatory assets and liabilities represent the future revenue impact from the reversal of deferred income taxes required for unamortized investment tax credits, the allowance for funds used during construction and deferred taxes provided at rates in excess of currently enacted rates.

DSM. KU's rates contain a DSM provision. The provision includes a rate mechanism that provides for concurrent recovery of DSM costs and provides an incentive for implementing DSM programs. The provision allows KU to recover revenues from lost sales associated with the DSM programs based on program plan engineering estimates and post-implementation evaluations.

In July 2007, KU and LG&E filed an application with the Kentucky Commission requesting an order approving enhanced versions of the existing DSM programs along with the addition of several new cost effective programs. The total annual budget for these programs is approximately $26 million, an increase over the previous annual costs of approximately $10 million. In March 2008, the Kentucky Commission issued an Order approving the application, with minor modifications. KU and LG&E filed revised tariffs in April 2008, under authority of this Order, which were effective in May 2008.

Other Regulatory Matters

Storm Restoration. In January 2009, a significant winter ice storm passed through KU's service territory causing approximately 199,000 customer outages, followed closely by a severe wind storm in February 2009, causing approximately 44,000 customer outages. KU currently estimates costs incurred of $66 million of expenses and $28 million of capital expenditures related to the restoration following the two storms. The Company expects to seek recovery of these costs from the Kentucky Commission.

Utility Competition in Virginia. The Commonwealth of Virginia passed the Virginia Electric Utility Restructuring Act in 1999. This act gave customers the ability to choose their electric supplier and capped electric rates through December 2010. KU subsequently received a legislative exemption from the customer choice requirements of this law. In April 2007, however, the Virginia General Assembly amended the Virginia Electric Utility Restructuring Act, thereby terminating this competitive market and commencing re-regulation of utility rates. The new act ended the cap on rates at the end of 2008. Pursuant to this legislation, the Virginia Commission adopted regulations revising the rules governing utility rate increase applications. As of January 2009, a hybrid model of regulation is being applied in Virginia. Under this model, utility rates are reviewed every two years. KU's exemption from the requirements of the Virginia Electric Utility Restructuring Act in 1999, however, discharges KU from the requirements of the new hybrid model of regulation. In lieu of submitting an annual information filing, KU has the option of requesting a change in base rates to recover prudently incurred costs by filing a traditional base rate case. KU is also subject to other utility regulations in Virginia, including, but not limited to, the recovery of prudently incurred fuel costs through an annual fuel factor charge and the submission of integrated resource plans.

Regional Reliability Council. KU has changed its regional reliability council membership from the Reliability First Corporation to the SERC, effective January 1, 2007. Regional reliability councils are industry consortiums that promote, coordinate and ensure the reliability of the bulk electric supply systems in North America.

TC2 CCN Application and Transmission Matters. A CCN application for construction of the new base-load, coal fired unit known as TC2, which will be jointly owned by KU and LG&E, together with the IMEA and the IMPA, was approved by the Kentucky Commission in November 2005.

CCN applications for two transmission lines associated with the TC2 unit were approved by the Kentucky Commission in September 2005 and May 2006. All regulatory approvals and rights of way for one transmission line have been obtained.

The CCN for the remaining line has been challenged by certain Hardin County, Kentucky property owners. In August 2006, KU and LG&E obtained a successful dismissal of the challenge at the Franklin County circuit court, which ruling was reversed by the Kentucky Court of Appeals in December 2007, and the proceeding reinstated. The matter is currently before the Kentucky Supreme Court on a motion for discretionary review filed by KU and LG&E in May 2008. The motion, which seeks reversal of the appellate court decision and reinstatement of the circuit court dismissal of the challenge has not yet been ruled upon.

Completion of the transmission lines are also subject to standard construction permit, environmental authorization and real property or easement acquisition procedures and certain Hardin County landowners have raised challenges to such a transmission line in some of these forums as well. During 2008, KU and LG&E obtained various successful rulings at the Hardin County circuit court establishing their condemnation and easement rights. In August 2008, the landowners appealed such rulings to the Kentucky Court of Appeals and received a stay preventing KU and LG&E access to the properties during the appeal. KU and LG&E have petitioned the appellate court to lift the stay and otherwise sustain the lower court ruling, but such matter has not yet been ruled upon. In a separate proceeding, certain Hardin County landowners have also challenged the same transmission line in federal district court in Louisville, Kentucky, claiming that certain National Historic Preservation Act requirements were not fully complied with by the U.S. Army relating to easements for the line through Fort Knox. KU and LG&E are cooperating with the U.S. Army in its defense in this case.

KU and LG&E continue to actively engage in settlement negotiations with the Hardin County property owners involved in the appeals of the condemnation proceedings. During the fourth quarter of 2008, KU and LG&E entered into settlements with certain Meade County landowners and obtained dismissals of prior litigation they had brought challenging the same transmission line. KU and LG&E are not currently able to predict the ultimate outcome and possible effects, if any, on the construction schedule relating to these transmission line approval and land acquisition proceedings.

Ghent FGD Inquiry. In October 2006, the Kentucky Commission commenced an inquiry into elements of KU's planned construction of one of its three new FGDs at the Ghent generating station. The proceeding requested, and the Company provided, additional information regarding configuration details, expenditures and the proposed construction sequence applicable to future construction phases of the Ghent FGD project. In January 2007, the Kentucky Commission issued an Order completing its inquiry in the matter and confirming its approval of KU's construction plan. The Order also provided general guidance for jurisdictional utilities regarding applicable information and data requirements for future CCN applications and subsequent proceedings.

Market-Based Rate Authority. In July 2006, the FERC issued an Order in KU's market-based rate proceeding accepting KU's further proposal to address certain market power issues the FERC had claimed would arise upon an exit from the MISO. In particular, the Company received permission to sell power at market-based rates at the interface of control areas in which it may be deemed to have market power, subject to a restriction that such power not be collusively re-sold back into such control areas. However, restrictions exist on sales by KU of power at market-based rates in the KU/LG&E and Big Rivers Electric Corporation control areas. In June 2007, the FERC issued Order No. 697 implementing certain reforms to market-based rate regulations, including restrictions similar to those previously in place for KU's power sales at control area interfaces. In December 2008, the FERC issued Order No. 697-B potentially placing additional restrictions on certain power sales involving areas where market power is deemed to exist. The Order is subject to a FERC rehearing process during which time the FERC has delayed implementation of the provisions relating to sales at interfaces. The Company cannot determine its ultimate impact at this time. As a condition of receiving and retaining market-based rate authority, KU must comply with applicable affiliate restrictions set forth in the FERC's regulation. During September 2008, KU submitted a regular tri-annual update filing under market-based rate regulations and FERC review proceedings for such filing remain in progress.

Mandatory Reliability Standards. As a result of the EPAct 2005, certain formerly voluntary reliability standards became mandatory in June 2007, and authority was delegated to various RROs by the NERC, which was authorized by the FERC to enforce compliance with such standards, including promulgating new standards. Failure to comply with mandatory reliability standards can subject a registered entity to sanctions, including potential fines of up to $1 million per day, as well as non-monetary penalties, depending upon the circumstances of the violation. KU is a member of the SERC, which acts as KU's RRO. During May 2008, the SERC and KU agreed to a settlement involving penalties totaling less than $1 million related to KU's February 2008 self-report concerning possible violations of certain existing mitigation plans relating to reliability standards. The SERC and KU are currently involved in settlement negotiations concerning a June 2008 self-report by KU relating to three other standards and an October 2008 self-report of a possible violation relating to an additional standard. SERC proceedings for these June and October self-reports are in the early stages and therefore the outcome is unable to be determined. Mandatory reliability standard settlements commonly include other non-penalty elements, including compliance steps and mitigation plans. Settlements with the SERC proceed to NERC and FERC review before becoming final. In December 2008, the SERC commenced a routine, periodic audit of KU and LG&E relating to certain designated reliability standards. This audit was completed during the first quarter of 2009 with no violations identified. While KU believes itself to be in compliance with the mandatory reliability standards, the Company cannot predict the outcome of other analyses, including on-going SERC or other reviews described above.

IRP. Integrated resource planning regulations in Kentucky require major utilities to make triennial IRP filings with the Kentucky Commission. In April 2008, KU and LG&E filed their 2008 joint IRP with the Kentucky Commission. The IRP provides historical and projected demand, resource and financial data, and other operating performance and system information. The AG and the KIUC were granted intervention in the IRP proceeding. During September 2008, KU and LG&E responded to public comments and they are awaiting the Kentucky Commission staff report which will close this proceeding. KU and LG&E are not able to predict further proceedings at this time.

PUHCA 2005. E.ON, KU's ultimate parent, is a registered holding company under PUHCA 2005. E.ON, its utility subsidiaries, including KU, and certain of its non-utility subsidiaries, are subject to extensive regulation by the FERC with respect to numerous matters, including: electric utility facilities and operations, wholesale sales of power and related transactions, accounting practices, issuances and sales of securities, acquisitions and sales of utility properties, payments of dividends out of capital and surplus, financial matters and inter-system sales of non-power goods and services. KU believes that it has adequate authority (including financing authority) under existing FERC orders and regulations to conduct its business and will seek additional authorization when necessary.

EPAct 2005. The EPAct 2005 was enacted in August 2005. Among other matters, this comprehensive legislation contains provisions mandating improved electric reliability standards and performance; granting enhanced civil penalty authority to the FERC; providing economic and other incentives relating to transmission, pollution control and renewable generation assets; increasing funding for clean coal generation incentives; repealing the Public Utility Holding Company Act of 1935; enacting PUHCA 2005 and expanding FERC jurisdiction over public utility holding companies and related matters via the Federal Power Act and PUHCA 2005.

In February 2006, the Kentucky Commission initiated an administrative proceeding to consider the requirements of the EPAct 2005, Subtitle E Section 1252, Smart Metering, which concerns time-based metering and demand response, and Section 1254, Interconnections. EPAct 2005 requires each state regulatory authority to conduct a formal investigation and issue a decision on whether or not it is appropriate to implement certain Section 1252, Smart Metering standards within eighteen months after the enactment of EPAct 2005 and to commence consideration of Section 1254, Interconnection standards within one year after the enactment of EPAct 2005. Following a public hearing with all Kentucky jurisdictional electric utilities, in December 2006, the Kentucky Commission issued an Order in this proceeding indicating that the EPAct 2005 Section 1252, Smart Metering and Section 1254, Interconnection standards should not be adopted. However, all five Kentucky Commission jurisdictional utilities are required to file real-time pricing pilot programs for their large commercial and industrial customers. KU developed a real-time pricing pilot for large industrial and commercial customers and filed the details of the plan with the Kentucky Commission in April 2007. Data discovery concluded in July 2007, and no parties to the case requested a hearing. In February 2008, the Kentucky Commission issued an Order approving the real-time pricing pilot program proposed by KU for implementation within approximately eight months, for its large commercial and industrial customers. The tariff was filed in October 2008, with an effective date of December 1, 2008. KU will file annual reports on the program within 90 days of each plan year-end for the 3-year pilot period.

Green Energy Riders. In February 2007, KU and LG&E filed a Joint Application and Testimony for Proposed Green Energy Riders. The AG and KIUC were granted full intervention. In May 2007, a Kentucky Commission Order was issued authorizing KU to establish Small and Large Green Energy Riders, allowing customers to contribute funds to be used for the purchase of renewable energy credits.

Home Energy Assistance Program. In July 2007, KU filed an application with the Kentucky Commission for the establishment of a new Home Energy Assistance program. During September 2007, the Kentucky Commission approved the new five-year program as filed, effective in October 2007. The program terminates in September 2012, and is funded through a $0.10 per month meter charge. Effective February 6, 2009, as a result of the settlement agreement in the 2008 base rate case, the program is funded through a $0.15 per month meter charge.

Collection Cycle Revision. As part of the base rate case filed on July 29, 2008, LG&E proposed to change the due date for customer bill payments from 15 days to 10 days to align its collection cycle with KU. In addition, KU proposed to include a late payment charge if payment is not received within 15 days from the bill issuance date to align with LG&E. The settlement agreement approved in the rate case in February 2009, changed the due date for customer bill payments to 12 days after bill issuance for both KU and LG&E, and KU will implement a late payment charge if payment is not received within 15 days from the bill issuance date.

Depreciation Study. In December 2007, KU filed a depreciation study with the Kentucky Commission as required by a previous Order. An adjustment to the depreciation rates is dependent on an order being received from the Kentucky Commission. In July 2008, KU filed a motion to consolidate the procedural schedule of the depreciation study with the application for a change in base rates. In August 2008, the Kentucky Commission issued an Order consolidating the depreciation study with the base rate case proceeding. The settlement agreement in the rate case established new depreciation rates effective February 2009. KU also filed the depreciation study with the Virginia Commission, but has not requested formal review and approval of the depreciation rates from the Virginia Commission. Such a review will take place either during KU's next base rate case in Virginia or when KU makes a formal application to the Virginia Commission for approval of the proposed rates.

Brownfield Development Rider Tariff. In March 2008, KU received Kentucky Commission approval for a Brownfield Development Rider, which offers a discounted rate to electric customers who meet certain usage and location requirements, including taking new service at a brownfield site, as certified by the appropriate Kentucky state agency. The rider would permit special contracts with such customers which provide for a series of declining partial rate discounts over an initial five-year period of a longer service arrangement. The tariff is intended to promote local economic redevelopment and efficient usage of utility resources by aiding potential reuse of vacant brownfield sites.

Interconnection and Net Metering Guidelines. In May 2008, the Kentucky Commission on its own motion initiated a proceeding to establish interconnection and net metering guidelines in accordance with amendments to existing statutory requirements for net metering of electricity. The jurisdictional electric utilities and intervenors in this case presented proposed interconnection guidelines to the Kentucky Commission in October 2008. In a January 2009 Order, the Kentucky Commission issued the Interconnection and Net Metering Guidelines – Kentucky that were developed by all parties to the proceeding. KU does not expect any impact as a result of this Order. KU shall file revised net metering tariffs and application forms within ninety days of the Order to comply with the new guidelines.

EISA 2007 Standards. In November 2008, the Kentucky Commission initiated an administrative proceeding to consider new standards as a result of the Energy Independence and Security Act of 2007 ("EISA 2007"), part of which amends the Public Utility Regulatory Policies Act of 1978 ("PURPA"). There are four new PURPA standards and one non-PURPA standard applicable to electric utilities. The proceeding also considers two new PURPA standards applicable to natural gas utilities. EISA 2007 requires state regulatory commissions and nonregulated utilities to begin consideration of the rate design and smart grid investments no later than December 19, 2008 and to complete the consideration by December 19, 2009.

Note 3 - Financial Instruments

The cost and estimated fair values of KU's non-trading financial instruments as of December 31 follow:

	2008		2007	
(in millions)	Carrying Value	Fair Value	Carrying Value	Fair Value
Long-term debt	$ 351	$ 349	$ 333	$ 333
Long-term debt from affiliate	$ 1,181	$ 1,117	$ 931	$ 996

The long-term debt valuations reflect prices quoted by dealers. The fair value of the long-term debt from affiliate is determined using an internal valuation model that discounts the future cash flows of each loan at current market rates. The current market rates are determined based on quotes from investment banks that are actively involved in capital markets for utilities and factor in KU's credit ratings and default risk. The fair values of cash and cash equivalents, accounts receivable, cash surrender value of key man life insurance, accounts payable and notes payable are substantially the same as their carrying values.

KU is subject to the risk of fluctuating interest rates in the normal course of business. KU's policies allow the interest rate risk to be managed through the use of fixed rate debt, floating rate debt and interest rate swaps. At December 31, 2008, a 100 basis point change in the benchmark rate on KU's variable rate debt would impact pre-tax interest expense by $3 million annually. Although KU's policies allow for the use of interest rate swaps, as of December 31, 2008, KU had no interest rate swaps outstanding.

Energy Trading and Risk Management Activities. KU conducts energy trading and risk management activities to maximize the value of power sales from physical assets it owns. Energy trading activities are principally forward financial transactions to manage price risk and are accounted for as non-hedging derivatives on a mark-to-market basis in accordance with SFAS No. 133, as amended.

Energy trading and risk management contracts are valued using prices based on active trades on the Intercontinental Exchange ("ICE"). In the absence of a traded price, midpoints of the best bids and offers will be the primary determinants of valuation. When sufficient trading activity is unavailable, other inputs can include prices quoted by brokers or observable inputs other than quoted prices, such as one-sided bids or offers, as of the balance sheet date. Using these valuation methodologies, these contracts are considered level 2 based on SFAS No. 157 measurement criteria. Quotes are verified quarterly using an independent pricing source of actual transactions. Quotes for combined off-peak and weekend timeframes are allocated between the two timeframes based on their historical proportional ratios to the integrated cost. No other adjustments are made to the forward prices.

No changes to valuation techniques for energy trading and risk management activities occurred during 2008 or 2007. Changes in market pricing, interest rate and volatility assumptions were made during both years. All contracts outstanding at December 31, 2008 and 2007, had a maturity of less than one year and were considered to be in a liquid market.

KU maintains policies intended to minimize credit risk and revalues credit exposures daily to monitor compliance with those policies. At December 31, 2008, 100% of the trading and risk management commitments were with counterparties rated BBB-/Baa3 equivalent or better. KU has reserved against counterparty credit risk based on the counterparty's credit rating and applying historical default rates within varying credit ratings over time provided by S&P or Moody's. At December 31, 2008 and 2007, counterparty credit reserves were less than $1 million.

KU manages the price volatility of its forecasted electric wholesale sales with the sales of market-traded electric forward contracts. Hedge accounting treatment has not been elected for these transactions, and therefore gains and losses are shown in the statements of income. Unrealized gains and losses are included in other expense – net, whereas realized gains and losses are included in operating revenues. Unrealized losses were $1 million and unrealized gains were less than $1 million in 2008 and 2007, respectively. Realized gains and losses were less than $1 million in 2008 and 2007.

Effective January 1, 2008, KU adopted the required provisions of SFAS No. 157, excluding the exceptions related to nonfinancial assets and liabilities, which will be adopted effective January 1, 2009, consistent with FASB Staff Position 157-2. KU has classified the applicable financial assets that are accounted for at fair value into the three levels of the fair value hierarchy, as defined by SFAS No. 157.

The following table sets forth by level within the fair value hierarchy KU's financial assets that were accounted for at fair value on a recurring basis as of December 31, 2008. Cash collateral related to the energy trading and risk management contracts totals less than $1 million, is categorized as restricted cash and is a level 1 measurement based on the funds being held in liquid accounts. Liabilities accounted for at fair value total less than $1 million and use level 2 measurements. There are no level 3 measurements for this period.

Recurring Fair Value Measurements (in millions)	Level 1	Level 2	Total
Financial Assets:			
Energy trading and risk management contracts	$ -	$ 1	$ 1
Total Financial Assets	$ -	$ 1	$ 1

Note 4 - Concentrations of Credit and Other Risk

Credit risk represents the accounting loss that would be recognized at the reporting date if counterparties failed to perform as contracted. Concentrations of credit risk (whether on- or off-balance sheet) relate to groups of customers or counterparties that have similar economic or industry characteristics that would cause their ability to meet contractual obligations to be similarly affected by changes in economic or other conditions.

KU's customer receivables and revenues arise from deliveries of electricity to approximately 508,000 customers in over 600 communities and adjacent suburban and rural areas in 77 counties in central, southeastern and western Kentucky, to approximately 30,000 customers in 5 counties in southwestern Virginia and 5 customers in Tennessee. For the years ended December 31, 2008 and 2007, 100% of total revenue was derived from electric operations. During 2008, KU's 10 largest customers accounted for less than 10% of electric volumes.

Effective August 1, 2006, KU and its employees represented by the IBEW Local 2100 entered into a new three-year collective bargaining agreement. The new agreement provides for negotiated increases or changes to wages, benefits or other provisions and for annual wage re-openers. Wage re-openers were negotiated and agreed to in July 2007 and July 2008. KU and employees represented by the USWA Local 9447-01 entered into a three-year collective bargaining agreement in August 2008. The new agreement provides for negotiated increases or changes to wages, benefits or other provisions and for annual wage re-openers. The employees represented by these two bargaining units comprise approximately 16% of KU's workforce at December 31, 2008.

Note 5 - Pension and Other Postretirement Benefit Plans

KU employees benefit from both funded and unfunded non-contributory defined benefit pension plans and other postretirement benefit plans that together cover employees hired by December 31, 2005. Employees hired after this date participate in the Retirement Income Account ("RIA"), a defined contribution plan. The Company makes an annual lump sum contribution to the RIA, based on years of service and a percentage of covered compensation. The health care plans are contributory with participants' contributions adjusted annually. KU uses December 31 as the measurement date for its plans.

Obligations and Funded Status. The following tables provide a reconciliation of the changes in the plans' benefit obligations and fair value of assets over the two-year period ending December 31, 2008, and a statement of the funded status as of December 31 for KU's sponsored defined benefit plans:

(in millions)	Pension Benefits		Other Postretirement Benefits	
	2008	2007	2008	2007
Change in benefit obligation				
Benefit obligation at beginning of year	$ 284	$ 303	$ 76	$ 88
Service cost	5	6	1	2
Interest cost	18	17	5	5
Benefits paid, net of retiree contributions	(18)	(19)	(3)	(5)
Actuarial (gain)/loss and other	17	(23)	(4)	-
Benefit obligation at end of year	$ 306	$ 284	$ 75	$ 90
Change in plan assets				
Fair value of plan assets at beginning of year	$ 264	$ 253	$ 13	$ 12
Actual return on plan assets	(61)	17	(3)	-
Employer contributions	-	13	5	6
Benefits paid, net of retiree contributions	(18)	(19)	(3)	(5)
Administrative expenses and other	(2)	-	-	-
Fair value of plan assets at end of year	$ 183	$ 264	$ 12	$ 13
Funded status at end of year	$ (123)	$ (20)	$ (63)	$ (77)

Amounts Recognized in Statement of Financial Position. The following tables provide the amounts recognized in the balance sheets and information for plans with benefit obligations in excess of plan assets as of December 31:

(in millions)	Pension Benefits		Other Postretirement Benefits	
	2008	2007	2008	2007
Regulatory assets	$ 137	$ 37	$ (10)	$ (9)
Accrued benefit liability (non-current)	(123)	(20)	(63)	(63)

Additional year-end information for plans with accumulated benefit obligations in excess of plan assets:

(in millions)	Pension Benefits		Other Postretirement Benefits	
	2008	2007	2008	2007
Benefit obligation	$ 306	$ 284	$ 75	$ 76
Accumulated benefit obligation	261	243	-	-
Fair value of plan assets	183	264	12	13

For discussion of the pension and postretirement regulatory assets, see Note 2, Rates and Regulatory Matters.

Components of Net Periodic Benefit Cost. The following tables provide the components of net periodic benefit cost for pension and other postretirement benefit plans. The tables include the costs associated with both KU employees and E.ON U.S. Services' employees, who are providing services to the utility. The E.ON U.S. Services' costs that are allocated to KU are approximately 46% and 45% of E.ON U.S. Services' total cost for 2008 and 2007, respectively.

Pension Benefits

(in millions)	KU 2008	Servco Allocation to KU 2008	Total KU 2008	KU 2007	Servco Allocation to KU 2007	Total KU 2007
Service cost	$ 6	$ 4	$ 10	$ 6	$ 4	$ 10
Interest cost	18	6	24	17	5	22
Expected return on plan assets	(21)	(5)	(26)	(21)	(5)	(26)
Amortization of prior service costs	1	1	2	1	1	2
Amortization of actuarial loss	-	-	-	2	1	3
Benefit cost at end of year	$ 4	$ 6	$ 10	$ 5	$ 6	$ 11

Other Postretirement Benefits

	KU 2008	Servco Allocation to KU 2008	Total KU 2008	KU 2007	Servco Allocation to KU 2007	Total KU 2007
Service cost	$ 1	$ 1	$ 2	$ 1	$ 1	$ 2
Interest cost	5	-	5	5	-	5
Expected return on plan assets	(1)	-	(1)	(1)	-	(1)
Amortization of transitional obligation	1	-	1	1	-	1
Benefit cost at end of year	$ 6	$ 1	$ 7	$ 6	$ 1	$ 7

The assumptions used in the measurement of KU's pension benefit obligation are shown in the following table:

	2008	2007
Weighted-average assumptions as of December 31:		
Discount rate	6.25%	6.66%
Rate of compensation increase	5.25%	5.25%

The discount rates were determined by the December 29, 2008, Mercer Pension Discount Yield Curve. These discount rates were then lowered by 2 basis points for the average change in 4 bond indices, Citigroup High Grade Credit Index AAA/AA 10+ years, Lehman Brothers US AA Long Credit, Merrill Lynch US Corporate AA-AAA rated 10+ years and Merrill Lynch US Corporate AA rated 15+ years, for the period from December 29, 2008 to December 31, 2008.

The assumptions used in the measurement of KU's net periodic benefit cost are shown in the following table:

	2008	2007
Discount rate	6.66%	5.96%
Expected long-term return on plan assets	8.25%	8.25%
Rate of compensation increase	5.25%	5.25%

To develop the expected long-term rate of return on assets assumption, KU considered the current level of expected returns on risk free investments (primarily government bonds), the historical level of the risk premium associated with the other asset classes in which the portfolio is invested and the expectations for future returns of each asset class. The expected return for each asset class was then weighted based on the target asset allocation to develop the expected long-term rate of return on assets assumption for the portfolio.

The following describes the effects on pension benefits by changing the major actuarial assumptions discussed above:

- A 1% change in the assumed discount rate could have an approximate $31 million positive or negative impact to the 2008 accumulated benefit obligation and an approximate $42 million positive or negative impact to the 2008 projected benefit obligation.
- A 25 basis point change in the expected rate of return on assets would have an approximate $1 million positive or negative impact on 2008 pension expense.

Assumed Health care Cost Trend Rates. For measurement purposes, an 8% annual increase in the per capita cost of covered health care benefits was assumed for 2008. The rate was assumed to decrease gradually to 5% by 2016 and remain at that level thereafter.

Assumed health care cost trend rates have a significant effect on the amounts reported for the health care plans. A 1% change in assumed health care cost trend rates would have resulted in an increase or decrease of less than $1 million on the 2008 total of service and interest costs components and an increase or decrease of $4 million in year-end 2008 postretirement benefit obligations.

Expected Future Benefit Payments and Medicare Subsidy Receipts. The following list provides the amount of expected future benefit payments, which reflect expected future service and the estimated gross amount of

Medicare subsidy receipts:

(in millions)	Pension Benefits	Other Postretirement Benefits	Medicare Subsidy Receipts
2009	$ 18	$ 7	$ 1
2010	18	7	-
2011	17	7	1
2012	17	7	-
2013	17	7	1
2014-18	94	39	3

Plan Assets. The following table shows KU's weighted-average asset allocation by asset category at December 31:

Pension Plans	Target Range	2008	2007
Equity securities	45% - 75%	55%	57%
Debt securities	30% - 50%	43	43
Other	0% - 10%	2	-
Totals		100%	100%

The investment policy of the pension plans was developed in conjunction with financial consultants, investment advisors and legal counsel. The goal of the investment policy is to preserve the capital of the fund and maximize investment earnings. The return objective is to exceed the benchmark return for the policy index comprised of the following: Russell 3000 Index, MSCI-EAFE Index, Lehman Aggregate and Lehman U.S. Long Government/Credit Bond Index in proportions equal to the targeted asset allocation.

Evaluation of performance focuses on a long-term investment time horizon of at least three to five years or a complete market cycle. The assets of the pension plans are broadly diversified within different asset classes (equities, fixed income securities and cash equivalents).

To minimize the risk of large losses in a single asset class, no more than 5% of the portfolio will be invested in the securities of any one issuer with the exclusion of the U.S. government and its agencies. The equity portion of the fund is diversified among the market's various subsections to diversify risk, maximize returns and avoid undue exposure to any single economic sector, industry group or individual security. The equity subsectors include, but are not limited to, growth, value, small capitalization and international.

In addition, the overall fixed income portfolio may have an average weighted duration, or interest rate sensitivity which is within +/- 20% of the duration of the overall fixed income benchmark. Foreign bonds in the aggregate shall not exceed 10% of the total fund. The portfolio may include a limited investment of up to 20% in below investment grade securities provided that the overall average portfolio quality remains "AA" or better. The below investment grade securities include, but are not limited to, medium-term notes, corporate debt, non-dollar and emerging market debt and asset backed securities. The cash investments should be in securities that either are of short maturities (not to exceed 180 days) or readily marketable with modest risk.

Derivative securities are permitted only to improve the portfolio's risk/return profile, to modify the portfolio's duration or to reduce transaction costs and must be used in conjunction with underlying physical assets in the portfolio. Derivative securities that involve speculation, leverage, interest rate anticipation, or any undue risk whatsoever are not deemed appropriate investments.

The investment objective for the postretirement benefit plan is to provide current income consistent with stability of principal and liquidity while maintaining a stable net asset value of $1.00 per share. The postretirement funds are invested in a prime cash money market fund that invests primarily in a portfolio of short-term, high-quality fixed income securities issued by banks, corporations and the U.S. government.

Contributions. KU made a discretionary contribution to the pension plan of $13 million in January 2007. In addition, contributions to other postretirement benefit plans of $5 million and $6 million were made in 2008 and 2007, respectively. The amount of future contributions to the pension plan will depend upon the actual return on plan assets and other factors, but the Company funds its pension obligations in a manner consistent with the Pension Protection Act of 2006. In 2009, KU anticipates making voluntary contributions to fund Voluntary Employee Beneficiary Association trusts to match the annual postretirement expense and funding the 401(h) plan up to the maximum amount allowed by law.

Pension Legislation. The Pension Protection Act of 2006 was enacted in August 2006. New rules regarding funding of defined benefit plans are generally effective for plan years beginning in 2008. Among other matters, this comprehensive legislation contains provisions applicable to defined benefit plans which generally (i) mandate full funding of current liabilities within seven years; (ii) increase tax-deduction levels regarding contributions; (iii) revise certain actuarial assumptions, such as mortality tables and discount rates; and (iv) raise federal insurance premiums and other fees for under-funded and distressed plans. The legislation also contains a number of provisions relating to defined-contribution plans and qualified and non-qualified executive pension plans and other matters. The Company has monitored developments regarding the Act and has made a number of elections to comply.

Thrift Savings Plans. KU has a thrift savings plan under section 401(k) of the Internal Revenue Code. Under the plan, eligible employees may defer and contribute to the plan a portion of current compensation in order to provide future retirement benefits. KU makes contributions to the plan by matching a portion of the employee contributions. The costs of this matching were $3 million and $2 million for 2008 and 2007, respectively.

KU also makes contributions to retirement income accounts within its thrift savings plans for certain employees not covered by its noncontributory defined benefit pension plans. These employees consist mainly of those hired after December 31, 2005. KU makes these contributions based on years of service and the employees' wage and salary levels, and it makes them in addition to the matching contributions discussed above. The amounts contributed by KU under this arrangement equaled less than $1 million in 2008 and in 2007.

Note 6 - Income Taxes

A United States consolidated income tax return is filed by E.ON U.S.'s direct parent, E.ON US Investments Corp., for each tax period. Each subsidiary of the consolidated tax group, including KU, calculates its separate income tax for each period. The resulting separate-return tax cost or benefit is paid to or received from the parent company or its designee. KU also files income tax returns in various state jurisdictions. While the federal statute of limitations related to 2005 and later years are open, Revenue Agent Reports for 2005-2007 have been received from the IRS, effectively closing these years to additional audit adjustments. Adjustments made by the IRS for the 2005-2006 tax years were recorded in the 2008 financial statements. The tax year 2007 return was examined under an IRS pilot program named "Compliance Assurance Process" ("CAP"). This program accelerates the IRS's review to begin during the year applicable to the return and ends 90 days after the return is filed. KU had no adjustments for the 2007 filed federal income tax return. The tax year 2008 return is also being examined under the CAP program.

KU adopted the provisions of FIN 48, *Accounting for Uncertainty in Income Taxes, an Interpretation of SFAS No. 109,* effective January 1, 2007. At the date of adoption, KU had less than $1 million of unrecognized tax benefits, primarily related to federal income taxes. If recognized, the amount of unrecognized tax benefits would reduce the effective income tax rate. Additions and reductions of uncertain tax positions during 2008 and 2007 were less than $1 million. Possible amounts of uncertain tax positions for KU that may decrease within the next 12 months total less than $1 million and are based on the expiration of the audit periods as defined in the statutes.

Interest and penalties, if any, are recorded as operating expenses on the income statement and accrued expenses on the balance sheet. The amount KU recognized as interest expense and interest accrued related to unrecognized tax benefits was less than $1 million as of December 31, 2008 and 2007. The interest accrued is based on IRS and Kentucky Department of Revenue large corporate interest rates for underpayment of taxes. At the date of adoption, KU accrued less than $1 million in interest expense on uncertain tax positions. No penalties were accrued by KU upon adoption of FIN 48, or through December 31, 2008.

Components of income tax expense are shown in the table below:

(in millions)		2008	2007
Current	- federal	$ 46	$ 28
	- state	10	13
Deferred	- federal – net	(10)	(5)
	- state – net	(3)	(1)
Investment tax credit – deferred		25	43
Amortization of investment tax credit		-	(1)
Total income tax expense		$ 68	$ 77

Current federal income tax expense increased and investment tax credit – deferred decreased primarily due to claiming $18 million less in investment tax credits in 2008. These investment tax credits are discussed further below. Current state income tax decreased due to coal credits claimed in 2008. Deferred federal income tax decreased due to adjusting prior year estimates to actual based on the filed tax return.

In June 2006, KU and LG&E filed a joint application with the U.S. Department of Energy ("DOE") requesting certification to be eligible for investment tax credits applicable to the construction of TC2. In November 2006, the DOE and the IRS announced that KU and LG&E were selected to receive the tax credit. A final IRS certification required to obtain the investment tax credit was received in August 2007. In September 2007, KU received an Order from the Kentucky Commission approving the accounting of the investment tax credit. KU's portion of the TC2 tax credit will be approximately $100 million over the construction period and will be amortized to income over the life of the related property beginning when the facility is placed in service. Based on eligible construction expenditures incurred, KU recorded investment tax credits of $25 million and $43 million in 2008 and 2007, respectively, decreasing current federal income taxes. In addition, a full depreciation basis adjustment is required for the amount of the credit. The income tax expense impact of this adjustment will begin when the facility is placed in service.

In March 2008, certain environmental and preservation groups filed suit in federal court in North Carolina against the DOE and IRS claiming the investment tax credit program was in violation of certain environmental laws and demanded relief, including suspension or termination of the program. In August 2008, the plaintiffs submitted an amended complaint alleging additional claims for relief. In November 2008, the Court dismissed the suit; however, the plaintiffs filed a motion for reconsideration. The Company is not currently a party to this proceeding and is not able to predict the ultimate outcome of this matter.

Components of net deferred tax liabilities included in the balance sheets are shown below:

(in millions)	2008	2007
Deferred tax liabilities:		
Depreciation and other plant-related items	$ 284	$ 292
Regulatory assets and other	40	40
Total deferred tax liabilities	324	332
Deferred tax assets:		
Income taxes due to customers	6	9
Pensions and related benefits	19	17
Liabilities and other	22	23
Total deferred tax assets	47	49
Net deferred income tax liability	$ 277	$ 283
Balance sheet classification		
Current assets	$ (3)	$ (2)
Non-current liabilities	280	285
Net deferred income tax liability	$ 277	$ 283

KU expects to have adequate levels of taxable income to realize its recorded deferred tax assets.

A reconciliation of differences between the statutory U.S. federal income tax rate and KU's effective income tax rate follows:

	2008	2007
Statutory federal income tax rate	35.0 %	35.0 %
State income taxes, net of federal benefit	2.6	3.4
Reduction of income tax reserve	(0.2)	(0.4)
Qualified production activities deduction	(1.1)	(1.2)
Dividends received deduction related to EEI investment	(4.2)	(2.9)
Amortization of investment tax credits	(0.1)	(0.4)
Other differences	(1.9)	(1.9)
Effective income tax rate	30.1 %	31.6 %

State income taxes, net of federal benefit decreased due to state coal credits received in 2008. KU's effective income tax rate also decreased in 2008 as a result of increased dividends from its investment in EEI.

Note 7 - Long-Term Debt

As of December 31, 2008 and 2007, long-term debt consists primarily of pollution control bonds and long-term loans from affiliated companies as summarized below.

(in millions)	Stated Interest Rates	Maturities	Principal Amounts
Outstanding at December 31, 2008	Variable – 7.035%	2010-2037	$1,532
Outstanding at December 31, 2007	Variable – 6.33%	2010-2037	$1,264

Pollution control series bonds are obligations of KU issued in connection with tax-exempt pollution control revenue bonds issued by various governmental entities, principally counties in Kentucky. A loan agreement obligates KU to make debt service payments to the county that equate to the debt service due from the county on the related pollution control revenue bonds. Until a series of financing transactions was completed during February 2007, the county's debt was also secured by an equal amount of KU's first mortgage bonds that were pledged to the trustee for the pollution control revenue bonds that match the terms and conditions of the county's debt, but require no payment of principal and interest unless the Company defaults on the loan agreement. Subsequent to February 2007, the loan agreement is an unsecured obligation of KU. Proceeds from bond issuances for environmental equipment (primarily related to the installation of FGDs) were held in trust pending expenditure for qualifying assets. At December 31, 2008, and 2007, KU had $9 million and $11 million, respectively, of bond proceeds in trust, included in restricted cash in the balance sheets.

Several of the pollution control bonds are or were insured by monoline bond insurers whose ratings have been under pressure due to exposures relating to insurance of sub-prime mortgages. At December 31, 2008, KU had an aggregate $351 million of outstanding pollution control indebtedness, of which $96 million is in the form of insured auction rate securities wherein interest rates are reset every 35 days via an auction process. Beginning in late 2007, the interest rates on these insured bonds began to increase due to investor concerns about the creditworthiness of the bond insurers. In 2008, interest rates have continued to increase, and the Company has experienced "failed auctions" where there are insufficient bids for the bonds. When there is a failed auction, the interest rate is set pursuant to a formula stipulated in the indenture which can be as high as 15%. During 2008 and 2007, the average rate on the auction rate bonds was 4.50% and 3.96%, respectively. The instruments governing these auction rate bonds permit KU to convert the bonds to other interest rate modes, such as various short-term variable rates, long-term fixed rates or intermediate-term fixed rates that are reset infrequently. In 2008, the ratings of the following bonds were downgraded due to downgrades of the bond insurers or the termination of the bond insurance.

($ in millions)		Bond Rating			
		Moody's		S&P	
Tax Exempt Bond Issues	Principal	2008	2007	2008	2007
Mercer County 2000 Series A (1)	$ 13	Aaa	Aaa	AA+	AAA
Carroll County 2002 Series C	$ 96	A2	Aaa	A	AAA
Carroll County 2004 Series A (1)	$ 50	Aaa	Aaa	AA+	AAA
Carroll County 2005 Series A (2)	$ 13	-	Aaa	-	AAA
Carroll County 2005 Series B (2)	$ 13	-	Aaa	-	AAA
Carroll County 2006 Series A (2)	$ 17	-	Aaa	-	AAA
Carroll County 2006 Series B (1)	$ 54	Aaa	Aaa	AA+	AAA
Carroll County 2006 Series C (2)	$ 17	-	Aaa	-	AAA
Carroll County 2007 Series A	$ 18	A2	Aaa	A	AAA
Trimble County 2007 Series A	$ 9	A2	Aaa	A	AAA
Carroll County 2008 Series A (3)	$ 78	Aaa	-	AA+	-

(1) Bonds restructured in December 2008, and enhanced by letter of credit. Bond insurance terminated upon restructuring.
(2) Bonds defeased in October 2008. Proceeds combined with new bond allocation of $18 million to create new bond issue of $78 million without insurance enhancement.
(3) Bond issued in October 2008, without insurance enhancement. Bond restructured in December 2008, and enhanced by letter of credit.

In February 2008, KU issued a notice to bondholders of its intention to convert the Carroll County 2007 Series A bond and the Trimble County 2007 Series A bond from the auction rate mode to a fixed interest rate mode, as permitted under the loan documents. These conversions were completed in April 2008, and the new rates on the bonds are 5.75% and 6.00%, respectively.

In March 2008, KU issued notices to bondholders of its intention to convert the Carroll County 2006 Series C bond and the Mercer County 2000 Series A bond from the auction rate mode to a weekly interest rate mode, as permitted under the loan documents. The Carroll County conversion was completed in April 2008, and the Mercer County conversion was completed in May 2008. In connection with these conversions, KU purchased the bonds from the remarketing agent. In October 2008, the Carroll County 2006 Series C bond, along with the Carroll County 2005 Series A and B and Carroll County 2006 Series A bonds, were defeased.

In June 2008, KU issued notices to bondholders of its intention to convert the Carroll County 2004 Series A bond from the auction rate mode to a weekly interest rate mode, as permitted under the loan documents. The conversion was completed in July 2008. In connection with the conversion, KU purchased the bond from the remarketing agent.

In November 2008, KU issued notices to bondholders of its intention to convert the Carroll County 2006 Series B and Carroll County 2008 Series A bonds from the auction rate mode to a weekly interest rate mode, as permitted under the loan documents. The conversion was completed in December 2008. In connection with the conversions, the bond insurance policy associated with the bonds was terminated and replaced with letters of credit.

In December 2008, KU remarketed the Mercer County 2000 Series A and Carroll County 2004 Series A bonds. In connection with the conversions, the bond insurance policy associated with the bonds was terminated and replaced with letters of credit.

As of December 31, 2008, KU had no remaining repurchased bonds. KU refinanced and remarketed $63 million and refinanced $17 million of pollution control bonds that had been previously repurchased by the Company.

All of KU's first mortgage bonds were released and terminated in February 2007. Only the tax-exempt pollution control revenue bonds issued by the counties remain. Under the provisions for certain of KU's variable-rate pollution control bonds, the bonds are subject to tender for purchase at the option of the holder and to mandatory tender for purchase upon the occurrence of certain events. The average annualized interest rate for these bonds during 2008 and 2007 was 1.75% and 3.72%, respectively.

Redemptions and maturities of long-term debt for 2008 and 2007 are summarized below:

($ in millions) Year	Description	Principal Amount	Rate	Secured/ Unsecured	Maturity
2008	Pollution control bonds	$ 13	Variable	Secured	2035
2008	Pollution control bonds	$ 13	Variable	Secured	2035
2008	Pollution control bonds	$ 17	Variable	Secured	2036
2008	Pollution control bonds	$ 17	Variable	Secured	2036
2007	Pollution control bonds	$ 54	Variable	Secured	2024
2007	First mortgage bonds	$ 54	7.92%	Secured	2007

Issuances of long-term debt for 2008 and 2007 are summarized below:

($ in millions) Year	Description	Principal Amount	Rate	Secured/ Unsecured	Maturity
2008	Due to Fidelia	$ 75	7.035%	Unsecured	2018
2008	Pollution control bonds	$ 78	Variable	Unsecured	2032
2008	Due to Fidelia	$ 50	6.16%	Unsecured	2018
2008	Due to Fidelia	$ 50	5.645%	Unsecured	2018
2008	Due to Fidelia	$ 75	5.85%	Unsecured	2023
2007	Pollution control bonds	$ 54	Variable	Unsecured	2034
2007	Pollution control bonds	$ 18	Variable	Unsecured	2026
2007	Pollution control bonds	$ 9	Variable	Unsecured	2037
2007	Due to Fidelia	$ 53	5.69%	Unsecured	2022
2007	Due to Fidelia	$ 75	5.86%	Unsecured	2037
2007	Due to Fidelia	$ 50	5.98%	Unsecured	2017
2007	Due to Fidelia	$ 100	5.96%	Unsecured	2028
2007	Due to Fidelia	$ 70	5.71%	Unsecured	2019
2007	Due to Fidelia	$ 100	5.45%	Unsecured	2014

In October 2008, KU issued Carroll County 2008 Series A tax exempt bond in the amount of $78 million. The new bond matures on February 1, 2032, and bears interest at a variable rate. The new bond refinances four existing bonds (Carroll County 2005 Series A and C - $13 million each and the Carroll County 2006 Series A and C - $17 million each), and includes $18 million of new funding. The proceeds from the new funding will be held in escrow pending incurrence of qualifying expenditures.

In December 2008, KU converted the interest rate mode of the Carroll County 2006 Series B to a weekly mode from an auction mode. The bond along with the Carroll County 2004 Series A, the Mercer County 2000 Series A, and the Carroll County 2008 Series A, were issued with the enhancement of a letter of credit.

In February 2007, KU completed a series of financial transactions impacting its periodic reporting requirements. The $54 million Pollution Control Series 10 bond was refinanced and replaced with a new unsecured tax-exempt bond of the same amount maturing in 2034. The $53 million Series P bond was defeased and replaced with an intercompany loan totaling $53 million from Fidelia. In conjunction with the defeasance, the Company terminated the related interest rate swap. Fidelia also agreed to eliminate the second lien on its two secured loans. Pursuant to the terms of the remaining tax-exempt bonds, the first mortgage bonds were cancelled and the underlying lien on substantially all of KU's assets was released following the completion of these steps. KU no longer has any secured debt and is no longer subject to periodic reporting under the Securities Exchange Act of 1934.

Long-term debt maturities for KU are shown in the following table:

(in millions)	
2009	$ -
2010	33
2011	-
2012	50
2013	175
Thereafter	1,274
Total	$ 1,532

Note 8 - Notes Payable and Other Short-Term Obligations

KU participates in an intercompany money pool agreement wherein E.ON U.S. and/or LG&E make funds available to KU at market-based rates (based on highly rated commercial paper issues) up to $400 million. Details of the balances are as follows:

($ in millions)	Total Money Pool Available	Amount Outstanding	Balance Available	Average Interest Rate
December 31, 2008	$ 400	$ 16	$ 384	1.49%
December 31, 2007	$ 400	$ 23	$ 377	4.75%

E.ON U.S. maintains revolving credit facilities totaling $313 million and $150 million at December 31, 2008 and 2007, respectively, to ensure funding availability for the money pool. At December 31, 2008, one facility, totaling $150 million, is with E.ON North America, Inc., while the remaining line, totaling $163 million, is with Fidelia; both are affiliated companies. The facility as of December 31, 2007, was with E.ON North America, Inc. The balances are as follows:

($ in millions)	Total Available	Amount Outstanding	Balance Available	Average Interest Rate
December 31, 2008	$ 313	$ 299	$ 14	2.05%
December 31, 2007	$ 150	$ 62	$ 88	4.97%

During June 2007, KU entered into a short-term bilateral line of credit totaling $35 million. During the third quarter of 2007, KU extended the maturity date on this facility to June 2012. There was no outstanding balance under this facility at December 31, 2008.

The covenants under this revolving line of credit include the following:

- The debt/total capitalization ratio must be less than 70%
- E.ON must own at least 66.667% of voting stock of KU directly or indirectly
- The corporate credit rating of the Company must be at or above BBB- and Baa3 as determined by S&P and Moody's
- A limitation on disposing of assets aggregating more than 15% of total assets as of December 31, 2006

KU was in compliance with these covenants at December 31, 2008.

In October 2008, KU closed on a new $78 million bilateral line of credit which has a 364 day maturity. This facility was terminated in December 2008 and replaced by four new letter of credit facilities to allow issuance of letters of credit totaling $198 million to support tax-exempt bonds totaling $195 million. The reimbursement agreements are identical and contain the following covenants:

- E.ON must own 75% of voting stock of KU directly or indirectly
- A limitation on disposing of assets aggregating more than 20% of total assets as of most recent quarter-end.

At December 31, 2008, KU had no remaining capacity for letters of credit under these facilities and was in compliance with these covenants.

Note 9 - Commitments and Contingencies

Operating Leases. KU leases office space, office equipment, plant equipment and vehicles and accounts for these leases as operating leases. In addition, KU reimburses LG&E for a portion of the lease expense paid by LG&E for KU's usage of office space leased by LG&E. Total lease expense was $9 million and $6 million for 2008 and 2007, respectively. The future minimum annual lease payments for operating leases for years subsequent to December 31, 2008, are shown in the following table:

(in millions)	
2009	$ 9
2010	5
2011	4
2012	4
2013	3
Thereafter	6
Total	$ 31

Owensboro Contract Litigation. In May 2004, the City of Owensboro, Kentucky and OMU commenced a suit now removed to the U.S. District Court for the Western District of Kentucky, against KU concerning a long-term power supply contract (the "OMU Agreement") with KU. The dispute involves interpretational differences regarding issues under the OMU Agreement, including various payments or charges between KU and OMU and rights concerning excess power, termination and emissions allowances. The complaint seeks in excess of $6 million in damages in connection with one of its claims for periods prior to 2004, plus damages in an unspecified amount for later-occurring periods on that claim and for other claims. OMU has additionally requested injunctive and other relief, including a declaration that KU is in material breach of the contract. KU has filed an answer in this proceeding denying the OMU claims and presenting counterclaims and amended such filing in January 2007, to include further counterclaims alleging additional damages.

In May 2006, OMU issued a notification of its intent to terminate the OMU agreement contract in May 2010, without cause, absent any earlier relief which may be permitted by the proceeding, pursuant to a July 2005 summary judgment ruling interpreting the contract termination provisions in OMU's favor.

In September and October 2008, the court granted rulings on a number of summary judgment petitions in KU's favor, including determinations that KU's interpretation of facilities charge fund payments was accurate; that KU is the proportionate owner of NOx allowances allocated to the OMU plant by the government; that OMU's claims disputing various back-up power charges should be dismissed and that's KU's counterclaim based on operations and maintenance practices should proceed to trial. The summary judgment rulings resulted in the dismissal of all of OMU's remaining claims against KU. The trial on KU's counterclaim occurred during October and November 2008. During February 2009, the court issued orders on the matters covered at trial, including (i) awarding KU an aggregate $9 million relating to the cost of NOx allowances charged by OMU to KU and the price of back-up power purchased by OMU from KU and (ii) denying KU's claim for damages based upon sub-par operations and availability of the OMU units. Those rulings, as well as all of the court's various prior rulings, including upholding early termination of the contract in spring 2010, remain subject to post-trial motions and appeal rights.

Sale and Leaseback Transaction. KU is a participant in a sale and leaseback transaction involving its 62% interest in two jointly owned CTs at KU's E.W. Brown generating station (Units 6 and 7). Commencing in December 1999, KU and LG&E entered into a tax-efficient, 18-year lease of the CTs. KU and LG&E have provided funds to fully defease the lease, and have executed an irrevocable notice to exercise an early purchase option contained in the lease after 15.5 years. The financial statement treatment of this transaction is no different than if KU had retained its ownership. The leasing transaction was entered into following receipt of required state and federal regulatory approvals.

In case of default under the lease, KU is obligated to pay to the lessor its share of certain fees or amounts. Primary events of default include loss or destruction of the CTs, failure to insure or maintain the CTs and unwinding of the transaction due to governmental actions. No events of default currently exist with respect to the lease. Upon any termination of the lease, whether by default or expiration of its term, title to the CTs reverts jointly to KU and LG&E.

At December 31, 2008, the maximum aggregate amount of default fees or amounts was $9 million, of which KU would be responsible for 62% (approximately $6 million). KU has made arrangements with E.ON U.S., via guarantee and regulatory commitment, for E.ON U.S. to pay KU's full portion of any default fees or amounts.

Letter of Credit. KU has provided letters of credit totaling $198 million supporting bonds of $195 million and a letter of credit totaling less than $1 million to support certain obligations related to workers' compensation.

Purchased Power. KU has purchased power arrangements with OMU and OVEC. Under the OMU agreement, which is presently expected to end in May 2010, KU purchases all of the output of an approximately 400-Mw coal-fired generating station not required by OMU. The amount of purchased power available to KU during 2009-2010, which is expected to be approximately 5% of KU's total Kwh native load energy requirements, is dependent upon a number of factors including the OMU units' availability, maintenance schedules, fuel costs and OMU requirements. Payments are based on the total costs of the station allocated per terms of the OMU agreement. Included in the total costs is KU's proportionate share of debt service requirements on $228 million of OMU bonds outstanding at December 31, 2008. The debt service is allocated to KU based on its annual allocated share of capacity, which averaged approximately 41% in 2008. KU does not guarantee the OMU bonds, or any requirements therein, in the event of default by OMU.

KU has a contract for purchased power with OVEC, terminating in 2026, for various Mw capacities. KU has an investment of 2.5% ownership in OVEC's common stock, which is accounted for on the cost method of accounting. KU's share of OVEC's output is 2.5%, approximately 55 Mw of generation capacity. Future obligations for power purchases are shown in the following table:

(in millions)	
2009	$ 26
2010	17
2011	10
2012	10
2013	10
Thereafter	155
Total	$ 228

Coal and Gas Purchase Obligations. KU has contracts to purchase coal and natural gas transportation. Future obligations are shown in the following table:

(in millions)	
2009	$ 442
2010	387
2011	363
2012	217
2013	59
Thereafter	-(a)
Total	$ 1,468

(a) Obligations after 2013 are indexed to future market prices and will not be included above until prices are set using the contracted methodology.

Construction Program. KU had $123 million of commitments in connection with its construction program at December 31, 2008.

In June 2006, KU and LG&E entered into a construction contract regarding the TC2 project. The contract is generally in the form of a lump-sum, turnkey agreement for the design, engineering, procurement, construction, commissioning, testing and delivery of the project, according to designated specifications, terms and conditions. The contract price and its components are subject to a number of potential adjustments which may serve to increase or decrease the ultimate construction price paid or payable to the contractor. The contract also contains standard representations, covenants, indemnities, termination and other provisions for arrangements of this type, including termination for convenience or for cause rights. The parties have commenced certain negotiations relating to potential construction cost increases due to higher labor and per diem costs above an established baseline, and certain safety and compliance costs resulting from a change in law. KU's share of additional costs from inception of the contract through the expected project completion in 2010 may be approximately $25 million.

TC2 Air Permit. The Sierra Club and other environmental groups filed a petition challenging the air permit issued for the TC2 baseload generating unit which was issued by the KDAQ in November 2005. The filing of the challenge did not stay the permit, so the Company was free to proceed with construction during the pendency of the action. In June 2007, the state hearing officer assigned to the matter recommended upholding the air permit with minor revisions. In September 2007, the Secretary of the Kentucky Environmental and Public Protection Cabinet issued a final Order approving the hearing officer's recommendation and upholding the permit. In September 2007, KU administratively applied for a permit revision to reflect minor design changes. In October 2007, the environmental groups submitted comments objecting to the draft permit revisions and, in part, attempting to reassert general objections to the generating unit. In January 2008, the KDAQ issued a final permit revision. The environmental groups did not appeal the final Order upholding the permit or file a petition challenging the permit revision by the applicable deadlines. However, in October 2007, the environmental groups filed a lawsuit in federal court seeking an order for the EPA to grant or deny their pending petition for the EPA to "veto" the state air permit and in April 2008, they filed a petition seeking veto of the permit revision. In September 2008, the EPA issued an Order denying nine of eleven claims alleged in one of the petitions, but finding deficiencies in two areas of the permit. The KDAQ revised the permit to address the issues identified in the EPA's Order, although the Sierra Club subsequently submitted comments objecting to the revisions. Although the Company does not expect material changes in the permit as a result of the various petitions, the EPA has yet to rule on several additional claims. The Company is currently unable to determine the final outcome of this matter or the impact of an unfavorable determination upon the Company's financial condition or results of operations.

Mine Safety Compliance Costs. In March 2006, the Mine Safety and Health Administration enacted Emergency Temporary Standards regulations and has issued additional regulations as the result of the passage of the Mine Improvement and New Emergency Response Act of 2006, which was signed into law in June 2006. At the state level, Kentucky and other states that supply coal to KU, have passed new mine safety legislation. These pieces of legislation require all underground coal mines to implement new safety measures and install new safety equipment. Under the terms of some of the coal contracts KU has in place, provisions are made to allow for price adjustments for compliance costs resulting from new or amended laws or regulations. KU has begun to receive information from the mines it contracts with regarding price adjustments related to these compliance costs and has hired a consultant to review all supplier claims for validity and reasonableness. At this time KU has not been notified of claims by all mines and is reviewing those claims it has received. An adjustment will be made to the value of the coal inventory once the amount is determinable, however, the amount cannot be estimated at this time. The Company expects to recover these costs through the FAC.

Environmental Matters. KU's operations are subject to a number of environmental laws and regulations in each of the jurisdictions in which it operates, governing, among other things, air emissions, wastewater discharges, the use, handling and disposal of hazardous substances and wastes, soil and groundwater contamination and employee health and safety.

Clean Air Act Requirements. The Clean Air Act establishes a comprehensive set of programs aimed at protecting and improving air quality in the United States by, among other things, controlling stationary sources of air emissions such as power plants. While the general regulatory framework for these programs is established at the federal level, most of the programs are implemented and administered by the states under the oversight of the EPA. The key Clean Air Act programs relevant to KU's business operations are described below.

Ambient Air Quality. The Clean Air Act requires the EPA to periodically review the available scientific data for six criteria pollutants and establish concentration levels in the ambient air sufficient to protect the public health and welfare with an extra margin for safety. These concentration levels are known as NAAQS. Each state must identify "nonattainment areas" within its boundaries that fail to comply with the NAAQS and develop a SIP to bring such nonattainment areas into compliance. If a state fails to develop an adequate plan, the EPA must develop and implement a plan. As the EPA increases the stringency of the NAAQS through its periodic reviews, the attainment status of various areas may change, thereby triggering additional emission reduction obligations under revised SIPs aimed to achieve attainment.

In 1997, the EPA established new NAAQS for ozone and fine particulates that required additional reductions in SO_2 and NOx emissions from power plants. In 1998, the EPA issued its final "NOx SIP Call" rule requiring reductions in NOx emissions of approximately 85% from 1990 levels in order to mitigate ozone transport from the midwestern U.S. to the northeastern U.S. To implement the new federal requirements, Kentucky amended its SIP in 2002 to require electric generating units to reduce their NOx emissions to 0.15 pounds weight per MMBtu on a company-wide basis. In 2005, the EPA issued the CAIR which required additional SO_2 emission reductions of 70% and NOx emission reductions of 65% from 2003 levels. The CAIR provided for a two-phase cap and trade program, with initial reductions of NOx and SO_2 emissions due by 2009 and 2010, respectively, and final reductions due by 2015. In 2006, Kentucky proposed to amend its SIP to adopt state requirements similar to those under the federal CAIR. Depending on the level of action determined necessary to bring local nonattainment areas into compliance with the new ozone and fine particulate standards, KU's power plants are potentially subject to additional reductions in SO_2 and NOx emissions. In March 2008, the EPA issued a revised NAAQS for ozone, which contains a more stringent standard than that contained in the previous regulation. At present, KU is unable to determine what, if any, additional requirements may be imposed to achieve compliance with the new ozone standard.

In July 2008, a federal appeals court issued a ruling finding deficiencies in the CAIR and vacating it. In December 2008, the Court amended its previous Order, directing the EPA to promulgate a new regulation, but leaving the CAIR in the interim. Depending upon the course of such matters, the CAIR could be superseded by new or revised NOx or SO_2 regulations with different or more stringent requirements and SIPs which incorporate CAIR requirements could be subject to revision. KU is also reviewing aspects of its compliance plan relating to the CAIR, including scheduled or contracted pollution control construction programs. Finally, as discussed below, the remand of the CAIR results in some uncertainty with respect to certain other EPA or state programs and proceedings and KU's and LG&E's compliance plans relating thereto, due to the interconnection of the CAIR and CAIR-associated steps with such associated programs. At present, KU is not able to predict the outcomes of the legal and regulatory proceedings related to the CAIR and whether such outcomes could have a material effect on the Company's financial or operational conditions.

Hazardous Air Pollutants. As provided in the 1990 amendments to the Clean Air Act, the EPA investigated hazardous air pollutant emissions from electric utilities and submitted a report to Congress identifying mercury emissions from coal-fired power plants as warranting further study. In 2005, the EPA issued the CAMR establishing mercury standards for new power plants and requiring all states to issue new SIPs including mercury requirements for existing power plants. The EPA issued a model rule which provides for a two-phase cap and trade program with initial reductions due by 2010 and final reductions due by 2018. The CAMR provided for reductions of 70% from 2003 levels. The EPA closely integrated the CAMR and CAIR programs to ensure that the 2010 mercury reduction targets would be achieved as a "co-benefit" of the controls installed for purposes of compliance with the CAIR.

In February 2008, a federal appellate court issued a decision vacating the CAMR. The EPA has announced that it intends to promulgate a new rule to replace the CAMR. Depending on the final outcome of the rulemaking, the CAMR could be replaced by new mercury reduction rules with different or more stringent requirements. Kentucky has also repealed its corresponding state mercury regulations. At present, KU is not able to predict the outcomes of the legal and regulatory proceedings related to the CAMR and whether such outcomes could have a material effect on the Company's financial or operational conditions.

Acid Rain Program. The 1990 amendments to the Clean Air Act imposed a two-phased cap and trade program to reduce SO_2 emissions from power plants that were thought to contribute to "acid rain" conditions in the northeastern U.S. The 1990 amendments also contained requirements for power plants to reduce NOx emissions through the use of available combustion controls.

Regional Haze. The Clean Air Act also includes visibility goals for certain federally designated areas, including national parks, and requires states to submit SIPs that will demonstrate reasonable progress toward preventing future impairment and remedying any existing impairment of visibility in those areas. In 2005, the EPA issued its CAVR detailing how the Clean Air Act's BART requirements will be applied to facilities, including power plants, built between 1962 and 1974 that emit certain levels of visibility impairing pollutants. Under the final rule, as the CAIR provided for more visibility improvement than BART, states are allowed to substitute CAIR requirements in their regional haze SIPs in lieu of controls that would otherwise be required by BART. The final rule has been challenged in the courts. Additionally, because the regional haze SIPs incorporate certain CAIR requirements, the remand of CAIR could potentially impact regional haze SIPs. See "Ambient Air Quality" above for a discussion of CAIR-related uncertainties.

Installation of Pollution Controls. Many of the programs under the Clean Air Act utilize cap and trade mechanisms that require a company to hold sufficient emissions allowances to cover its authorized emissions on a company-wide basis and do not require installation of pollution controls on every generating unit. Under cap and trade programs, companies are free to focus their pollution control efforts on plants where such controls are particularly efficient and utilize the resulting emission allowances for smaller plants where such controls are not cost effective. KU met its Phase I SO_2 requirements primarily through installation of FGD equipment on Ghent Unit 1. KU's strategy for its Phase II SO_2 requirements, which commenced in 2000, includes the installation of additional FGD equipment, as well as using accumulated emission allowances and fuel switching to defer certain additional capital expenditures. In order to achieve the NOx emission reductions and associated obligations, KU installed additional NOx controls, including SCR technology, during the 2000 to 2008 time period at a cost of $221 million. In 2001, the Kentucky Commission granted approval to recover the costs incurred by KU for these projects through the environmental surcharge mechanism. Such monthly recovery is subject to periodic review by the Kentucky Commission.

In order to achieve mandated emissions reductions, KU expects to incur additional capital expenditures totaling approximately $720 million during the 2009 through 2011 time period for pollution controls including FGD and SCR equipment, and additional operating and maintenance costs in operating such controls. In 2005, the Kentucky Commission granted approval to recover the costs incurred by the Company for these projects through the ECR mechanism. Such monthly recovery is subject to periodic review by the Kentucky Commission. KU believes its costs in reducing SO_2, NOx and mercury emissions to be comparable to those of similarly situated utilities with like generation assets. KU's compliance plans are subject to many factors including developments in the emission allowance and fuels markets, future legislative and regulatory enactments, legal proceedings and advances in clean air technology. KU will continue to monitor these developments to ensure that its environmental obligations are met in the most efficient and cost-effective manner. See "Ambient Air Quality" above for a discussion of CAIR-related uncertainties.

Potential GHG Controls. In 2005, the Kyoto Protocol for reducing GHG emissions took effect, obligating 37 industrialized countries to undertake substantial reductions in GHG emissions. The U.S. has not ratified the Kyoto Protocol and there are currently no mandatory GHG emission reduction requirements at the federal level. Legislation mandating GHG reductions has been introduced in the Congress, but no federal legislation has been enacted to date. In the absence of a program at the federal level, various states have adopted their own GHG emission reduction programs. Such programs have been adopted in various states including 11 northeastern U.S. states and the District of Columbia under the Regional GHG Initiative program and California. Substantial efforts to pass federal GHG legislation are on-going. In April 2007, the U.S. Supreme Court ruled that the EPA has the authority to regulate GHG under the Clean Air Act. KU is monitoring on-going efforts to enact GHG reduction requirements at the state and federal level and is assessing potential impacts of such programs and strategies to mitigate those impacts. KU is also monitoring on-going regulatory proceedings including the EPA's advanced notice of proposed rulemaking for regulation of GHGs under the existing authority of the Clean Air Act and proposed rules governing carbon sequestration. The new administration has announced its intention to exercise its existing authority under the Clean Air Act to achieve reductions in GHG emissions. KU is unable to predict whether mandatory GHG reduction requirements will ultimately be enacted. As a Company with significant coal-fired generating assets, KU could be substantially impacted by programs requiring mandatory reductions in GHG emissions, although the precise impact on the operations of KU, including the reduction targets and deadlines that would be applicable, cannot be determined prior to the enactment of such programs.

Brown New Source Review Litigation. In April 2006, the EPA issued an NOV alleging that KU had violated certain provisions of the Clean Air Act's new source review rules relating to work performed in 1997, on a boiler and turbine at KU's E.W. Brown generating station. In December 2006, the EPA issued a second NOV alleging the Company had exceeded heat input values in violation of the air permit for the unit. In March 2007, the Department of Justice filed a complaint in federal court in Kentucky alleging the same violations specified in the prior NOVs. The complaint sought civil penalties, including potential per-day fines, remedial measures and injunctive relief. In April 2007, KU filed an answer in the civil suit denying the allegations. In July 2007, the court entered a schedule providing for a July 2009 date for trial. In December 2008, the Company reached a tentative settlement with the government resolving all outstanding claims. The proposed consent decree provides for payment of a $1 million civil penalty; funding of $3 million in environmental mitigation projects; surrender of 53,000 excess SO_2 allowances; surrender of excess NOx allowances estimated at 650 allowances annually for eight years; installation of an FGD by December 31, 2010; installation of an SCR by December 31, 2012; and compliance with specified emission limits and operational restrictions. In February 2009, the proposed consent decree was lodged with the Court. In March 2009, the Court issued a consent decree approving the settlement.

Section 114 Requests. In August 2007, the EPA issued administrative information requests under Section 114 of the Clean Air Act requesting new source review-related data regarding certain projects undertaken at LG&E's Mill Creek 4 and Trimble County 1 generating units and KU's Ghent 2 generating unit. KU and LG&E have complied with the information requests and are not able to predict further proceedings in this matter at this time.

Ghent Opacity NOV. In September 2007, the EPA issued an NOV alleging that KU had violated certain provisions of the Clean Air Act's operating rules relating to opacity during June and July of 2007 at Units 1 and 3 of KU's Ghent generating station. The parties have met on this matter and KU has received no further communications from the EPA. KU is not able to estimate the outcome or potential effects of these matters, including whether substantial fines, penalties or remedial measures may result.

General Environmental Proceedings. From time to time, KU appears before the EPA, various state or local regulatory agencies and state and federal courts regarding matters involving compliance with applicable environmental laws and regulations. Such matters include remediation activities for elevated PCB levels at existing properties, liability under the Comprehensive Environmental Response, Compensation and Liability Act for cleanup at various off-site waste sites and claims regarding GHG emissions from KU's generating stations. Based on analysis to date, the resolution of these matters is not expected to have a material impact on the operations of KU.

Note 10 - Jointly Owned Electric Utility Plant

KU and LG&E have begun construction of TC2, a jointly owned unit at the Trimble County site. KU and LG&E own undivided 60.75% and 14.25% interests, respectively, in TC2. Of the remaining 25% of TC2, IMEA owns a 12.12% undivided interest and IMPA owns a 12.88% undivided interest. Each company is responsible for its proportionate share of capital cost during construction, and fuel, operation and maintenance cost when TC2 begins operation, which is expected to occur in 2010. In June 2008, LG&E transferred assets related to TC2 with a net book value of $10 million to KU.

	TC2				
	LG&E	KU	IMPA	IMEA	Total
Ownership interest	14.25%	60.75%	12.88%	12.12%	100%
Mw capacity	107	455	97	91	750

(in millions)

KU's 60.75% ownership:		LG&E's 14.25% ownership:	
Cost	$ 560	Cost	$ 136
Accumulated depreciation	-	Accumulated depreciation	2
Net book value	$ 560	Net book value	$ 134

	KU	LG&E
Construction work in progress (included in above)	$550	$132

KU and LG&E jointly own the following CTs and related equipment:

($ in millions)	KU				LG&E				Total			
Ownership Percentage	Mw Capacity	($) Cost	($) Depre-ciation	($) Net Book Value	Mw Capacity	($) Cost	($) Depre-ciation	($) Net Book Value	Mw Capacity	($) Cost	($) Depre-ciation	($) Net Book Value
KU47%, LG&E53% (a)	129	53	(12)	41	146	62	(15)	47	275	115	(27)	88
KU62%, LG&E38% (b)	190	82	(14)	68	118	51	(8)	43	308	133	(22)	111
KU71%, LG&E29% (c)	228	80	(18)	62	92	32	(6)	26	320	112	(24)	88
KU63%, LG&E37% (d)	404	137	(21)	116	236	79	(12)	67	640	216	(33)	183
KU71%, LG&E29% (e)	n/a	9	(2)	7	n/a	3	(1)	2	n/a	12	(3)	9

(a) Comprised of Paddy's Run 13 and E.W. Brown 5. In addition to the above jointly owned utility plant, there is an inlet air cooling system attributable to unit 5 and units 8-11 at the E.W. Brown facility. This inlet air cooling system is not jointly owned, however, it is used to increase production on the units to which it relates, resulting in an additional 88 Mw of capacity for KU.
(b) Comprised of units 6 and 7 at the E.W. Brown facility.
(c) Comprised of units 5 and 6 at the Trimble County facility.
(d) Comprised of CT Substation 7-10 and units 7, 8, 9 and 10 at the Trimble County facility.
(e) Comprised of CT Substation 5 and 6 and CT Pipeline at the Trimble County facility.

Both KU's and LG&E's participating share of direct expenses of the jointly owned plants is included in the corresponding operating expenses on its respective income statement (e.g., fuel, maintenance of plant, other operating expense).

Note 11 - Related Party Transactions

KU, subsidiaries of E.ON U.S. and subsidiaries of E.ON engage in related party transactions. Transactions between KU and E.ON U.S. subsidiaries are eliminated upon consolidation of E.ON U.S. Transactions between KU and E.ON subsidiaries are eliminated upon consolidation of E.ON. These transactions are generally performed at cost and are in accordance with the FERC regulations under PUHCA 2005 and the applicable Kentucky Commission and Virginia Commission regulations. The significant related party transactions are disclosed below.

Electric Purchases

KU and LG&E purchase energy from each other in order to effectively manage the load of their retail and wholesale customers. These sales and purchases are included in the statements of income as operating revenues and purchased power operating expense. KU intercompany electric revenues and purchased power expense for the years ended December 31, were as follows:

(in millions)	2008	2007
Electric operating revenues from LG&E	$ 80	$ 46
Purchased power from LG&E	109	93

Interest Charges

See Note 8, Notes Payable and Other Short-Term Obligations, for details of intercompany borrowing arrangements. Intercompany agreements do not require interest payments for receivables related to services provided when settled within 30 days.

KU's intercompany interest income and expense for the years ended December 31, were as follows:

(in millions)	2008	2007
Interest on money pool loans	$ 2	$ 6
Interest on Fidelia loans	56	35

Other Intercompany Billings

E.ON U.S. Services provides KU with a variety of centralized administrative, management and support services. These charges include payroll taxes paid by E.ON U.S. Services on behalf of KU, labor and burdens of E.ON U.S. Services employees performing services for KU, coal purchases and other vouchers paid by E.ON U.S. Services on behalf of KU. The cost of these services is directly charged to KU, or for general costs which cannot be directly attributed, charged based on predetermined allocation factors, including the following ratios: number of customers, total assets, revenues, number of employees and other statistical information. These costs are charged on an actual cost basis.

In addition, KU and LG&E provide services to each other and to E.ON U.S. Services. Billings between KU and LG&E relate to labor and overheads associated with union employees performing work for the other utility, charges related to jointly-owned generating units and other miscellaneous charges. Billings from KU to E.ON U.S. Services include cash received by E.ON U.S. Services on behalf of KU, primarily tax settlements, and other payments made by KU on behalf of other non-regulated businesses which are reimbursed through E.ON

U.S. Services.

Intercompany billings to and from KU for the years ended December 31, were as follows:

(in millions)	2008	2007
E.ON U.S. Services billings to KU	$ 227	$ 488
KU billings to LG&E	75	6
LG&E billings to KU	5	12
KU billings to E.ON U.S. Services	3	26

In June 2008, LG&E transferred assets related to TC2 with a net book value of $10 million to KU.

In March, June, September and December 2008, KU received capital contributions from its common shareholder, E.ON U.S., in the amounts of $25 million, $50 million, $50 million and $20 million, respectively.

In September and December 2007, KU received capital contributions from its shareholder, E.ON U.S. in the amount of $55 million and $20 million, respectively.

Note 12 – Subsequent Events

On January 13, 2009, KU, the AG, KIUC and all other parties to the rate case filed a settlement agreement with the Kentucky Commission. Under the terms of the settlement agreement, KU's base electric rates will decrease by $9 million annually. An Order approving the settlement was received on February 5, 2009. The new rates were implemented effective February 6, 2009. However, in connection with the application and effective date of the new rates, the VDT surcredit and merger surcredit, respectively, terminated, which will amount in increased revenues of approximately $16 million annually.

On January 27 and 28, 2009, a significant winter ice storm passed through KU's service territory causing approximately 199,000 customer outages, followed closely by a severe wind storm on February 11, 2009, causing approximately 44,000 customer outages. KU currently estimates costs incurred of $66 million of expenses and $28 million of capital expenditures related to the restoration following the two storms. The Company expects to seek recovery of these costs from the Kentucky Commission.

On February 19, 2009, the court issued post-trial orders in the litigation between KU and OMU, which orders awarded KU an aggregate $9 million related to disputed NOx allowance and back-up power pricing provisions, but denied a KU claim for damages relating to the availability of the OMU units. The orders are subject to certain appeal and other procedural rights prior to becoming final.

On March 17, 2009, the Court issued a consent decree approving the settlement in the Brown New Source Review litigation.

On March 19, 2009, the EPA issued an NOV alleging that KU violated certain provisions of the Clean Air Act's rules governing new source review and prevention of significant deterioration by installing FGD and SCR controls at its Ghent generating station without assessing potential increased sulfuric acid mist emissions. KU

BLANK

contends that the work in question, as pollution control projects, was exempt from the requirements cited by the EPA. The Company is currently unable to determine the final outcome of this matter or the impact of an unfavorable determination upon the Company's financial position or results of operations.

Note 13 – Notes to Statement of Cash Flows

Supplemental disclosures of cash flow information

(in millions)	2008	2007
Cash paid during the period for:		
Income taxes	$ 50	$ 38
Interest on borrowed money	13	15
Interest to affiliated companies on borrowed money	53	30

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Utilities Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2008/Q4

SUMMARY OF UTILITY PLANT AND ACCUMULATED PROVISIONS FOR DEPRECIATION. AMORTIZATION AND DEPLETION

Report in Column (c) the amount for electric function, in column (d) the amount for gas function, in column (e), (f), and (g) report other (specify) and in column (f) common function.

Line No.	Classification (a)	Total Company for the Current Year/Quarter Ended (b)	Electric (c)
1	Utility Plant		
2	In Service		
3	Plant in Service (Classified)	3,998,708,617	3,998,708,617
4	Property Under Capital Leases		
5	Plant Purchased or Sold		
6	Completed Construction not Classified	437,171,600	437,171,600
7	Experimental Plant Unclassified		
8	Total (3 thru 7)	4,435,880,217	4,435,880,217
9	Leased to Others		
10	Held for Future Use	10,137,562	10,137,562
11	Construction Work in Progress	1,176,440,172	1,176,440,172
12	Acquisition Adjustments		
13	Total Utility Plant (8 thru 12)	5,622,457,951	5,622,457,951
14	Accum Prov for Depr, Amort, & Depl	2,052,492,161	2,052,492,161
15	Net Utility Plant (13 less 14)	3,569,965,790	3,569,965,790
16	Detail of Accum Prov for Depr, Amort & Depl		
17	In Service:		
18	*Depreciation*	2,030,308,196	2,030,308,196
19	Amort & Depl of Producing Nat Gas Land/Land Right		
20	Amort of Underground Storage Land/Land Rights		
21	Amort of Other Utility Plant	22,052,248	22,052,248
22	Total In Service (18 thru 21)	2,052,360,444	2,052,360,444
23	Leased to Others		
24	Depreciation		
25	Amortization and Depletion		
26	Total Leased to Others (24 & 25)		
27	Held for Future Use		
28	Depreciation	131,717	131,717
29	Amortization		
30	Total Held for Future Use (28 & 29)	131,717	131,717
31	Abandonment of Leases (Natural Gas)		
32	Amort of Plant Acquisition Adj		
33	Total Accum Prov (equals 14) (22,26,30,31,32)	2,052,492,161	2,052,492,161

Name of Respondent Kentucky Utilities Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2008/Q4

SUMMARY OF UTILITY PLANT AND ACCUMULATED PROVISIONS FOR DEPRECIATION. AMORTIZATION AND DEPLETION

Gas (d)	Other (Specify) (e)	Other (Specify) (f)	Other (Specify) (g)	Common (h)	Line No.
					1
					2
					3
					4
					5
					6
					7
					8
					9
					10
					11
					12
					13
					14
					15
					16
					17
					18
					19
					20
					21
					22
					23
					24
					25
					26
					27
					28
					29
					30
					31
					32
					33

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Utilities Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2008/Q4

ELECTRIC PLANT IN SERVICE (Account 101, 102, 103 and 106)

1. Report below the original cost of electric plant in service according to the prescribed accounts.
2. In addition to Account 101, Electric Plant in Service (Classified), this page and the next include Account 102, Electric Plant Purchased or Sold; Account 103, Experimental Electric Plant Unclassified; and Account 106, Completed Construction Not Classified-Electric.
3. Include in column (c) or (d), as appropriate, corrections of additions and retirements for the current or preceding year.
4. For revisions to the amount of initial asset retirement costs capitalized, included by primary plant account, increases in column (c) additions and reductions in column (e) adjustments.
5. Enclose in parentheses credit adjustments of plant accounts to indicate the negative effect of such accounts.
6. Classify Account 106 according to prescribed accounts, on an estimated basis if necessary, and include the entries in column (c). Also to be included in column (c) are entries for reversals of tentative distributions of prior year reported in column (b). Likewise, if the respondent has a significant amount of plant retirements which have not been classified to primary accounts at the end of the year, include in column (d) a tentative distribution of such retirements, on an estimated basis, with appropriate contra entry to the account for accumulated depreciation provision. Include also in column (d)

Line No.	Account (a)	Balance Beginning of Year (b)	Additions (c)
1	1. INTANGIBLE PLANT		
2	(301) Organization	44,456	
3	(302) Franchises and Consents	83,453	
4	(303) Miscellaneous Intangible Plant	24,595,145	3,165,472
5	TOTAL Intangible Plant (Enter Total of lines 2, 3, and 4)	24,723,054	3,165,472
6	2. PRODUCTION PLANT		
7	A. Steam Production Plant		
8	(310) Land and Land Rights	10,874,264	
9	(311) Structures and Improvements	172,830,576	1,906,668
10	(312) Boiler Plant Equipment	1,157,891,864	329,238,053
11	(313) Engines and Engine-Driven Generators	-	
12	(314) Turbogenerator Units	209,431,756	15,051,497
13	(315) Accessory Electric Equipment	94,292,264	4,042,316
14	(316) Misc. Power Plant Equipment	23,624,053	130,243
15	(317) Asset Retirement Costs for Steam Production	9,249,179	
16	TOTAL Steam Production Plant (Enter Total of lines 8 thru 15)	1,678,193,956	350,368,777
17	B. Nuclear Production Plant		
18	(320) Land and Land Rights		
19	(321) Structures and Improvements		
20	(322) Reactor Plant Equipment		
21	(323) Turbogenerator Units		
22	(324) Accessory Electric Equipment		
23	(325) Misc. Power Plant Equipment		
24	(326) Asset Retirement Costs for Nuclear Production		
25	TOTAL Nuclear Production Plant (Enter Total of lines 18 thru 24)		
26	C. Hydraulic Production Plant		
27	(330) Land and Land Rights	879,312	
28	(331) Structures and Improvements	453,196	11,732
29	(332) Reservoirs, Dams, and Waterways	9,025,249	842,094
30	(333) Water Wheels, Turbines, and Generators	377,497	62,159
31	(334) Accessory Electric Equipment	85,383	
32	(335) Misc. Power PLant Equipment	101,512	
33	(336) Roads, Railroads, and Bridges	46,976	
34	(337) Asset Retirement Costs for Hydraulic Production	4,970	
35	TOTAL Hydraulic Production Plant (Enter Total of lines 27 thru 34)	10,974,095	915,985
36	D. Other Production Plant		
37	(340) Land and Land Rights	294,924	
38	(341) Structures and Improvements	35,982,154	
39	(342) Fuel Holders, Products, and Accessories	21,085,015	
40	(343) Prime Movers	344,638,939	7,907,366
41	(344) Generators	59,334,142	1,455
42	(345) Accessory Electric Equipment	30,957,013	8,817
43	(346) Misc. Power Plant Equipment	5,227,549	
44	(347) Asset Retirement Costs for Other Production	70,990	
45	TOTAL Other Prod. Plant (Enter Total of lines 37 thru 44)	497,590,726	7,914,728
46	TOTAL Prod. Plant (Enter Total of lines 16, 25, 35, and 45)	2,186,758,777	359,199,490

ELECTRIC PLANT IN SERVICE (Account 101, 102, 103 and 106) (Continued)

distributions of these tentative classifications in columns (c) and (d), including the reversals of the prior years tentative account distributions of these amounts. Careful observance of the above instructions and the texts of Accounts 101 and 106 will avoid serious omissions of the reported amount of respondent's plant actually in service at end of year.

7. Show in column (f) reclassifications or transfers within utility plant accounts. Include also in column (f) the additions or reductions of primary account classifications arising from distribution of amounts initially recorded in Account 102, include in column (e) the amounts with respect to accumulated provision for depreciation, acquisition adjustments, etc., and show in column (f) only the offset to the debits or credits distributed in column (f) to primary account classifications.

8. For Account 399, state the nature and use of plant included in this account and if substantial in amount submit a supplementary statement showing subaccount classification of such plant conforming to the requirement of these pages.

9. For each amount comprising the reported balance and changes in Account 102, state the property purchased or sold, name of vendor or purchase, and date of transaction. If proposed journal entries have been filed with the Commission as required by the Uniform System of Accounts, give also date

Retirements (d)	Adjustments (e)	Transfers (f)	Balance at End of Year (g)		Line No.
					1
			44,456		2
			83,453		3
			27,760,617		4
			27,888,526		5
					6
					7
			10,874,264		8
89,209			174,648,035		9
1,602,275			1,485,527,642		10
					11
3,477,445			221,005,808		12
975			98,333,605		13
15,404			23,738,892		14
			9,249,179		15
5,185,308			2,023,377,425		16
					17
					18
					19
					20
					21
					22
					23
					24
					25
					26
			879,312		27
			464,928		28
44,162			9,823,181		29
3,022			436,634		30
			85,383		31
			101,512		32
			46,976		33
			4,970		34
47,184			11,842,896		35
					36
			294,924		37
			35,982,154		38
			21,085,015		39
2,244,287			350,302,018		40
			59,332,687		41
			30,965,830		42
			5,227,549		43
			70,990		44
2,244,287			503,261,167		45
7,476,779			2,538,481,488		46

Name of Respondent Kentucky Utilities Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2008/Q4

ELECTRIC PLANT IN SERVICE (Account 101, 102, 103 and 106) (Continued)

Line No.	Account (a)	Balance Beginning of Year (b)	Additions (c)
47	3. TRANSMISSION PLANT		
48	(350) Land and Land Rights	24,574,118	990,800
49	(352) Structures and Improvements	8,383,208	5,247,332
50	(353) Station Equipment	190,399,734	8,230,776
51	(354) Towers and Fixtures	63,279,466	
52	(355) Poles and Fixtures	99,664,171	1,981,767
53	(356) Overhead Conductors and Devices	132,389,750	796,340
54	(357) Underground Conduit	448,760	
55	(358) Underground Conductors and Devices	1,114,762	
56	(359) Roads and Trails		
57	(359.1) Asset Retirement Costs for Transmission Plant	11,027	
58	TOTAL Transmission Plant (Enter Total of lines 48 thru 57)	520,264,996	17,247,015
59	4. DISTRIBUTION PLANT		
60	(360) Land and Land Rights	3,494,818	54,881
61	(361) Structures and Improvements	5,058,913	156,669
62	(362) Station Equipment	103,404,415	7,620,061
63	(363) Storage Battery Equipment		
64	(364) Poles, Towers, and Fixtures	197,916,777	49,998,602
65	(365) Overhead Conductors and Devices	185,080,180	39,362,248
66	(366) Underground Conduit	1,546,234	197,312
67	(367) Underground Conductors and Devices	72,833,558	24,121,790
68	(368) Line Transformers	248,465,276	9,715,429
69	(369) Services	83,122,059	31,373,686
70	(370) Meters	65,364,852	45,006
71	(371) Installations on Customer Premises	18,282,872	1,721
72	(372) Leased Property on Customer Premises		
73	(373) Street Lighting and Signal Systems	53,642,796	22,499,781
74	(374) Asset Retirement Costs for Distribution Plant	18,610	
75	TOTAL Distribution Plant (Enter Total of lines 60 thru 74)	1,038,231,360	185,147,186
76	5. REGIONAL TRANSMISSION AND MARKET OPERATION PLANT		
77	(380) Land and Land Rights		
78	(381) Structures and Improvements		
79	(382) Computer Hardware		
80	(383) Computer Software		
81	(384) Communication Equipment		
82	(385) Miscellaneous Regional Transmission and Market Operation Plant		
83	(386) Asset Retirement Costs for Regional Transmission and Market Oper		
84	TOTAL Transmission and Market Operation Plant (Total lines 77 thru 83)		
85	6. GENERAL PLANT		
86	(389) Land and Land Rights	2,575,972	
87	(390) Structures and Improvements	30,276,265	4,799,093
88	(391) Office Furniture and Equipment	18,966,210	3,253,866
89	(392) Transportation Equipment	18,955,799	12,992
90	(393) Stores Equipment	735,053	
91	(394) Tools, Shop and Garage Equipment	5,473,497	103,167
92	(395) Laboratory Equipment	3,160,383	
93	(396) Power Operated Equipment	270,943	
94	(397) Communication Equipment	17,194,612	2,908,983
95	(398) Miscellaneous Equipment	373,591	
96	SUBTOTAL (Enter Total of lines 86 thru 95)	97,982,325	11,078,101
97	(399) Other Tangible Property		
98	(399.1) Asset Retirement Costs for General Plant		
99	TOTAL General Plant (Enter Total of lines 96, 97 and 98)	97,982,325	11,078,101
100	TOTAL (Accounts 101 and 106)	3,867,960,512	575,837,264
101	(102) Electric Plant Purchased (See Instr. 8)		
102	(Less) (102) Electric Plant Sold (See Instr. 8)		
103	(103) Experimental Plant Unclassified		
104	TOTAL Electric Plant in Service (Enter Total of lines 100 thru 103)	3,867,960,512	575,837,264

Name of Respondent Kentucky Utilities Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2008/Q4

ELECTRIC PLANT IN SERVICE (Account 101, 102, 103 and 106) (Continued)

Retirements (d)	Adjustments (e)	Transfers (f)	Balance at End of Year (g)		Line No.
					47
		-482,597	25,082,321		48
			13,630,540		49
26,835		-15,045	198,588,630		50
		-47,830	63,231,636		51
59,888		-4,123,522	97,462,528		52
150,704		-3,494,170	129,541,216		53
			448,760		54
		-3,033	1,111,729		55
					56
			11,027		57
237,427		-8,166,197	529,108,387		58
					59
		482,597	4,032,296		60
			5,215,582		61
216			111,024,260		62
					63
17,166		3,821,322	251,719,535		64
43,383		3,862,278	228,261,323		65
			1,743,546		66
			96,955,348		67
140,396			258,040,309		68
			114,495,745		69
			65,409,858		70
			18,284,593		71
					72
2,020			76,140,557		73
			18,610		74
203,181		8,166,197	1,231,341,562		75
					76
					77
					78
					79
					80
					81
					82
					83
					84
					85
			2,575,972		86
172			35,075,186		87
			22,220,076		88
			18,968,791		89
			735,053		90
			5,576,664		91
			3,160,383		92
			270,943		93
			20,103,595		94
			373,591		95
172			109,060,254		96
					97
					98
172			109,060,254		99
7,917,559			4,435,880,217		100
					101
					102
					103
7,917,559			4,435,880,217		104

BLANK

FOOTNOTE DATA

Schedule Page: 204 Line No.: 41 Column: c

Sales tax adjustment resulted in a negative addition.

BLANK

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Utilities Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2008/Q4

ELECTRIC PLANT HELD FOR FUTURE USE (Account 105)

1. Report separately each property held for future use at end of the year having an original cost of $250,000 or more. Group other items of property held for future use.
2. For property having an original cost of $250,000 or more previously used in utility operations, now held for future use, give in column (a), in addition to other required information, the date that utility use of such property was discontinued, and the date the original cost was transferred to Account 105.

Line No.	Description and Location Of Property (a)	Date Originally Included in This Account (b)	Date Expected to be used in Utility Service (c)	Balance at End of Year (d)
1	Land and Rights:			
2				
3				
4				
5				
6				
7				
8				
9				
10				
11				
12				
13				
14				
15				
16				
17				
18				
19				
20				
21	Other Property:			
22	Trimble County Cooling Tower (hyperbolic) - Utility			
23	use temporarily discontinued March 2008	06/30/2008	2010	10,137,562
24				
25				
26				
27				
28				
29				
30				
31				
32				
33				
34				
35				
36				
37				
38				
39				
40				
41				
42				
43				
44				
45				
46				
47	Total			10,137,562

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Utilities Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2008/Q4

CONSTRUCTION WORK IN PROGRESS - - ELECTRIC (Account 107)

1. Report below descriptions and balances at end of year of projects in process of construction (107)
2. Show items relating to "research, development, and demonstration" projects last, under a caption Research, Development, and Demonstrating (see Account 107 of the Uniform System of Accounts)
3. Minor projects (5% of the Balance End of the Year for Account 107 or $100,000, whichever is less) may be grouped.

Line No.	Description of Project (a)	Construction work in progress - Electric (Account 107) (b)
1	STEAM PRODUCTION MAJOR	
2	TC2 - KU	396,423,467
3	BROWN 1, 2, 3 FGD	233,726,240
4	TC2 AIR QUALITY CONTROL SYSTEMS KU	152,293,728
5	KU SOX PROGRAM - GHENT 2 FGD SYSTEM	140,838,104
6	BROWN ASH POND EXPANSION PHASE 1	18,186,020
7	GH3 FGD	6,453,203
8	GHENT 1 CONTROLS MODERNIZATION	5,186,779
9	GHENT 4 CONTROLS MODERNIZATION	4,960,348
10	GH2 CT CELL REBUILD	3,511,494
11	BR 2 REHEAT INLET & OUTLET HEADER	3,170,091
12	GHENT 2 CONTROLS MODERNIZATION	3,141,868
13	SO3 SORBENT INJECTION	2,565,236
14	GHENT SO2 COMMON	1,872,738
15	GHENT SPILL PREVENTION CONTAINMENT CONTROL COMPLIANCE MODIFICATIONS	1,445,319
16	GH4 FGD	1,223,066
17	GH3 CATALYST LAYER PURCHASE & INSTALLATION	1,142,172
18	E.W. BROWN UNIT 3 SCR CONCEPTUAL ENGINEERING	1,009,718
19	GHENT ASH POND/LANDFILL	1,008,465
20	FUEL SUPPLY MANAGEMENT SYSTEM	942,509
21	MERCURY MONITORING KU	941,211
22	TRIMBLE COUNTY ASH/GYPSUM PONDS	921,539
23	BR3 COOLING TOWER STORM DAMAGE REPAIRS	813,369
24	BR1 AIR HEATER BASKET REPLACEMENT	623,093
25	DEVELOPMENT TYRONE OIL CONTAINMENT SPCC	527,081
26	GH4 ASH PIPE REPLACEMENT	436,131
27	GH1 CT CELL 1-1 REBUILD	426,823
28	REVISED BR2 TURBINE BLADES	424,297
29	GH4 CT CELL 4-5 REBUILD	417,311
30	GH3 CT CELL 3-6 REBUILD	416,234
31	GH3 CT CELL 3-5 REBUILD	410,849
32	BR1-1 SBAC REPLACEMENT	387,553
33	GH DOWNRIVER FLOATING WORK BARGE	359,455
34	GH MOORING CELL C-4	322,819
35	COAL BARGE UNLOADER BUCKET & CHAIN REPLACEMENT	299,837
36	DEVELOPMENT HAEFLING OIL CONTAINMENT SPCC	284,598
37	GHENT CONVEYOR BELT REPLACEMENT	273,117
38	BR2 PRECIPITATOR PLATE REPLACEMENT	271,161
39	GH1 ID FAN TRANSFORMER	235,675
40	TY 480V SWITCHGEAR REPLACEMENT	210,875
41	MAXIMO LICENSES	186,734
42	UMS GROUP INVESTMENT EVALUATION MODEL	173,243
43	TOTAL	1,176,440,172

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Utilities Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2008/Q4

CONSTRUCTION WORK IN PROGRESS - - ELECTRIC (Account 107)

1. Report below descriptions and balances at end of year of projects in process of construction (107)
2. Show items relating to "research, development, and demonstration" projects last, under a caption Research, Development, and Demonstrating (see Account 107 of the Uniform System of Accounts)
3. Minor projects (5% of the Balance End of the Year for Account 107 or $100,000, whichever is less) may be grouped.

Line No.	Description of Project (a)	Construction work in progress - Electric (Account 107) (b)
1	TY5-4 EL MILL CONVERSION	162,615
2	GH 4 4-2 CIRCULATING COOLING WATER HEAT EXCHANGER	152,237
3	GH4 GENERATOR REWEDGE	147,129
4	GH MISCELLANEOUS MOTORS	143,058
5	BR1 LOWER DEAD AIR SPACE ABATEMENT	135,699
6	GH2 CT CELL 2-6 REBUILD	129,688
7	GH2 CT CELL 2-5 REBUILD	129,688
8	BR3 CONTROL ROOM HVAC DEVELOPMENT	129,654
9	TY3 5-1 EL CONVERSION	128,244
10	GH MAIN BUILDING ROOF	126,430
11	GR3 DISTRIBUTED CONTROL SYSTEM UPGRADE	118,927
12	BR 1-2 SERVICE WATER PUMP REBUILD	117,994
13	GH2 AUXILIARY CONDENSATE 2-2 RETUBE	116,613
14	STEAM PRODUCTION MINOR	1,653,380
15		
16	HYDRAULIC POWER MAJOR	
17	DX3 OVERHAUL	1,399,263
18	DEVELOPMENT DIX CRANE ACCESS ROAD	129,384
19	HYDRAULIC POWER MINOR	64,994
20		
21	OTHER PRODUCTION MAJOR	
22	BR CT7 A/B CONVERSION - KU	6,391,713
23	BR CT9 MODIFICATIONS	686,722
24	BR CT UNDERGROUND PIPE SPCC	627,368
25	BR CT6 QUENCH NOZZLE REPLACEMENT	154,832
26	OTHER PRODUCTION MINOR	193,616
27		
28	TRANSMISSION MAJOR	
29	DEVELOPMENT FOR TRIMBLE COUNTY UNIT #2	42,479,239
30	LOUDEN AVE TO LANSDOWN 69KV MVA TRANSFORMER	4,691,177
31	N. AMERICAN STAINLESS 345-138 KV450 MVA TRANSFORMER	4,470,709
32	BR ASH POND EXPANSION - TRANSMISSION LINE RELOCATION	4,195,754
33	PRIORITY REPLACEMENT TRANSMISSION LINES	3,065,416
34	SPCC MODIFICATIONS FOR KU	1,605,833
35	MISCELLANEOUS SUBSTATION PROJECTS - KU	1,433,143
36	FAWKES 138-69KV, 150MVA	1,354,957
37	NAS TAP 345KV LINE	1,275,880
38	PRIORITY TRANSMISSION LINE	1,262,028
39	STORM DAMAGE TRANSMISSION LINE	1,056,537
40	GHENT-KENTON 138KV - P2 POLE REPLACEMENT	732,251
41	GHENT 345KV BREAKER ADDITION	629,509
42	PARAMETER UPGRADE TRANSMISSION LINE	430,973
43	TOTAL	1,176,440,172

Name of Respondent Kentucky Utilities Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2008/Q4

CONSTRUCTION WORK IN PROGRESS - - ELECTRIC (Account 107)

1. Report below descriptions and balances at end of year of projects in process of construction (107)
2. Show items relating to "research, development, and demonstration" projects last, under a caption Research, Development, and Demonstrating (see Account 107 of the Uniform System of Accounts)
3. Minor projects (5% of the Balance End of the Year for Account 107 or $100,000, whichever is less) may be grouped.

Line No.	Description of Project (a)	Construction work in progress - Electric (Account 107) (b)
1	LYNCH TO POCKET 69KV HOLMES MILL	391,664
2	SHELBYVILLE - SIMPSONVILLE 69KV THERMAL UPGRADE	373,727
3	CRITICAL SPARE 138/69KV TRANSFORMER	367,705
4	KU TRANSMISSION BLANKET	310,012
5	K7 PARAMETER UPGRADES TRANSMISSION LINE	295,512
6	MISCELLANEOUS TRANSMISSION CAPITAL	290,745
7	HIGHWAY 52 RELOCATION RICHMOND	277,094
8	INNOVATION DRIVE-SUBSTATION 138KV TAP	269,950
9	HORSECAVE TRANSFORMER SUB 799 RECONDUCTOR TAP TO SUB 611	265,139
10	UK MEDICAL CENTER CONTROL HOUSE RELOCATION	257,237
11	REPLACE FAILED HARLAN TRANSFORMER	242,556
12	LEBANON EAST SUBSTATION	232,036
13	NEW FACILITIES TRANSMISSION LINE	198,190
14	REPLACE UNDERRATED 69KV BREAKERS FAWKES SUBSTATION	194,998
15	TAYLOR CO TRANSFORMER	183,753
16	GARRARD COUNTY HIGH SCHOOL	179,919
17	HIGBY MILL UK MEDICAL CENTER SYSTEM PARAMETERS	174,546
18	DETROIT HARVESTER SECTION OF PARIS-LEXINGTON PLANT	173,262
19	RECONDUCTOR PARKERS MILL TAP 69KV	167,597
20	LOUDEN AVENUE HAEFLING 138 KV HIGHWAY RELOCATION	167,563
21	MILLERSBURG CONTROL HOUSE REPLACEMENT	164,141
22	NEW FACILITIES TRANSMISSION LINE 2008	161,125
23	TRANSMISSION LINE RELOCATION KU	133,243
24	OPEN SYSTEM INTERNATIONAL ENERGY MANAGEMENT SYSTEM	127,375
25	KU REMOTE TERMINAL UNIT PURCHASE	121,012
26	PURCHASE SPARE TRANSMISSION CIRCUIT BREAKERS	113,776
27	HARRODSBURG - ADD 69KV BREAKERS FOR CUSTOMER	112,379
28	DELVINTA 824 CARRIER ADDITION	109,270
29	TRANSMISSION MINOR	2,257,524
30		
31	DISTRIBUTION MAJOR	
32	PURCHASE PROPERTY FOR INNOVATION DR SUB #428-1	3,853,688
33	INSTALL LEBANON JUNCTION SUB	1,812,414
34	W360 LTC REBUILD	1,483,468
35	NEW BUSINESS SERVICE - U/G - SHELYVILLE	1,401,943
36	PURCHASE OF METERS	1,384,274
37	STORM PROJECT	1,321,114
38	NEW ELECTRIC SERVICE - O/H - NORTON	1,304,846
39	AIR GAS SUBSTATION	1,287,203
40	NEW ELECTRIC SERVICE - O/H - PINEVILLE	1,190,212
41	PURCHASE TRANSFORMER 315	1,068,301
42	PUBLIC WORKS RELOCATION - O/H - LEXINGTON	1,003,728
43	TOTAL	1,176,440,172

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Utilities Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2008/Q4

CONSTRUCTION WORK IN PROGRESS - - ELECTRIC (Account 107)

1. Report below descriptions and balances at end of year of projects in process of construction (107)
2. Show items relating to "research, development, and demonstration" projects last, under a caption Research, Development, and Demonstrating (see Account 107 of the Uniform System of Accounts)
3. Minor projects (5% of the Balance End of the Year for Account 107 or $100,000, whichever is less) may be grouped.

Line No.	Description of Project (a)	Construction work in progress - Electric (Account 107) (b)
1	BRYANT ROAD #3 SUBSTATION & TEMPORARY TRANSFORMER	938,428
2	ADD TRANSFORMER HORSE CAVE INDUSTRIAL	930,561
3	STORMS	866,977
4	PURCHASE PROPERTY LEXINGTON EAST AREA SUBSTATION	788,353
5	KU GENERAL RELIABILITY	782,279
6	CONSTRUCTION LEBANON EAST SUB	772,068
7	SCM REPAIR/REPLACE FAILED TRANSFORMERS	760,977
8	CITY OF BARDSTOWN SUB	749,919
9	PURCHASE TRANSFORMERS	703,164
10	PURCHASE 161X69 SPARE TRANSFORMER	693,043
11	TROUBLE ORDERS O/H	639,383
12	ADD TRANSFORMER UNION UNDERWEAR	633,411
13	DISTRIBUTION RELIABILITY	631,501
14	REPLACE SHUN PIKE TRANSFORMER	575,775
15	STAMPING GROUND INSTALL 10 MVA TRANSFORMER	548,358
16	BELL COUNTY COAL GARMEADA #2	495,746
17	TROUBLE ORDERS O/H	473,587
18	NEW BUSINESS RESIDENTIAL	470,092
19	REPLACE TRANSFORMER 7/14 WOODLAWN	461,610
20	REPLACE 69/34 TRANSFORMER DORCHESTER	438,507
21	SCM EARL GREEN RIVER PLANT TRANSFORMER	429,999
22	PUBLIC WORKS RELOCATION - O/H - ELIZABETHTOWN	428,645
23	NEW BUSINESS RESIDENTIAL - U/G - LEXINGTON	411,271
24	ROGERS GAP DISTRIBUTION	406,447
25	REPAIR/REPLACE DEFECTIVE STREET LIGHTS	386,397
26	WINTER STORM	374,402
27	DISTRIBUTION CAPACITORS KU	371,803
28	PURCHASE TRANSFORMERS	364,539
29	PURCHASE TRANSFORMERS	349,717
30	TROUBLE ORDERS	337,618
31	REPAIR REPLACE DEFECTIVE STREET LIGHTS	332,114
32	PURCHASE TRANSFORMER	326,048
33	PUBLIC WORKS RELOCATION - O/H - DANVILLE	306,348
34	BROWN 1, 2, 3 FGD	305,969
35	INSTALL NEW 795 CIRCUIT TO NESTLE PLANT	304,805
36	CONSTRUCT NEW CIRCUIT FROM BRYANT TEMPORARY SUB	294,965
37	SUBSTATION ABB TYPE TRANSFORMER REPLACEMENT	291,042
38	REPLACE TRANSFORMER AT KY STATE HOSPITAL SUB #587	274,679
39	SCM EARLINGTON SUBSTATION REPLACEMENT (S&C FUSES)	266,224
40	WINCHESTER WATER WORKS	254,763
41	NEW BUSINESS COMMERCIAL	251,108
42	WINDSTREAM TELEPHONE COMPANY POLE REPLACEMENT	249,740
43	TOTAL	1,176,440,172

Name of Respondent Kentucky Utilities Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2008/Q4

CONSTRUCTION WORK IN PROGRESS - - ELECTRIC (Account 107)

1. Report below descriptions and balances at end of year of projects in process of construction (107)
2. Show items relating to "research, development, and demonstration" projects last, under a caption Research, Development, and Demonstrating (see Account 107 of the Uniform System of Accounts)
3. Minor projects (5% of the Balance End of the Year for Account 107 or $100,000, whichever is less) may be grouped.

Line No.	Description of Project (a)	Construction work in progress - Electric (Account 107) (b)
1	KU DISTRIBUTION POWER FACTOR CORRECTION	247,660
2	NEW BUSINESS COMMERCIAL	244,147
3	NEW BUS INDUSTRIAL - U/G - ELIZABETHTOWN	239,590
4	OUTAGE MANAGEMENT SYSTEM UPGRADE	238,661
5	INNOVATION WEST CIRCUIT	237,062
6	TATES CREEK ROAD HIGHWAY RELOCATION	235,520
7	REPLACE DEFECTIVE EQUIPMENT - O/H - PINEVILLE	234,199
8	ELIZABETHTOWN - STORM RESTORATION	232,034
9	NEW BUSINESS RESIDENTIAL	230,581
10	SCM TRANSFORMER REWINDERS	229,670
11	LONDON - STORM RESTORATION	226,445
12	TOOLS AND EQUIPMENT	218,137
13	KU MOBILE INFRASTRUCTURE	214,118
14	TOOLS AND EQUIPMENT	211,362
15	NEW BUSINESS RESIDENTIAL - O/H - LEXINGTON	209,646
16	TOOLS AND EQUIPMENT	207,294
17	STRATTON PIKE REBUILD	206,772
18	INNOVATION - U/G - EXIT CIRCUITS	194,510
19	UNION UNDERWEAR CIRCUIT WORK	190,563
20	HIGHWAY RELOCATION KY 1577	189,564
21	BOGGS LANE	185,147
22	PURCHASE TRANSFORMERS	178,199
23	LEXINGTON STORM RESTORATION	177,308
24	SYSTEM ENHANCEMENTS - EXISTING CUSTOMERS - LEXINGTON	176,958
25	SHELBYVILLE STORM RESTORATION	176,242
26	PUBLIC WORKS RELOCATION - O/H - LONDON	169,772
27	PAYNES DEPOT RD (US62) HIGHWAY	168,552
28	NEW BUS RESIDENTIAL - O/H - LONDON	167,027
29	DISTRIBUTION RELIABILITY	166,661
30	HORSE CAVE RECONDUCTORING	165,066
31	EARLINGTON STORM RESTORATION	164,483
32	KU PC & PRINTER INFRASTRUCTURE	164,430
33	HORSE CAVE INDUSTRIAL SUBSTATION DISTRIBUTION WORK	159,632
34	SCM REPLACE BREAKERS	157,951
35	TOOLS AND EQUIPMENT	157,517
36	PURCHASE TRANSFORMERS	157,126
37	PUBLIC WORKS RELOCATION - O/H - MAYSVILLE	154,891
38	NEW BUSINESS RESIDENTIAL - O/H - NORTON	152,126
39	LONDON FAWN VALLEY ESTATES SUBDIVISION U/G SYSTEM	152,049
40	ADD REGULATORS AT ANDOVER	148,703
41	PURCHASE TRANSFORMERS	148,156
42	NEW BUSINESS INDUSTRIAL	144,749
43	TOTAL	1,176,440,172

Name of Respondent Kentucky Utilities Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2008/Q4

CONSTRUCTION WORK IN PROGRESS - - ELECTRIC (Account 107)

1. Report below descriptions and balances at end of year of projects in process of construction (107)
2. Show items relating to "research, development, and demonstration" projects last, under a caption Research, Development, and Demonstrating (see Account 107 of the Uniform System of Accounts)
3. Minor projects (5% of the Balance End of the Year for Account 107 or $100,000, whichever is less) may be grouped.

Line No.	Description of Project (a)	Construction work in progress - Electric (Account 107) (b)
1	SYSTEM ENHANCEMENTS - NEW CUSTOMERS - RICHMOND	140,938
2	KU GENERAL RELIABILITY	138,942
3	NEW DOUBLE CIRCUIT TO CITATION BLVD.	135,394
4	KU SUBS REMOTE TERMINAL UNIT INSTALLS FOR EKPC METERING	134,851
5	TROUBLE ORDERS	134,605
6	NEW BUSINESS COMMERCIAL - O/H - LEXINGTON	134,295
7	BRYANT ROAD #3 EXIT CIRCUIT	133,402
8	FOURMILE RECONDUCTOR ELECTRIC	131,587
9	PUBLIC WORKS RELOCATION - O/H - RICHMOND	128,010
10	DISTRIBUTION RELIABILITY	124,344
11	PUBLIC WORKS RELOCATION - O/H - NORTON	119,676
12	KY 519 HIGHWAY RELOCATION	117,757
13	PUBLIC WORKS RELOCATION - O/H - SHELBYVILLE	116,073
14	KU STORM WORK	114,997
15	SCM CENTRAL SPARTA UPGRADE	114,592
16	NEW BUSINESS SUBDIVISION - U/G - PINEVILLE	113,275
17	LEXINGTON AREA IMPROVEMENTS	108,407
18	NEW BUSINESS SERVICE - U/G - LEXINGTON	106,938
19	RELOCATIONS CUSTOMER REQUEST	104,197
20	NEW BUSINESS RESIDENTIAL - O/H - EARLINGTON	102,022
21	WISE CIRCUIT 4642	101,773
22	SYSTEM ENHANCEMENT - EXISTING CUSTOMERS EARLINGTON	100,763
23	PURCHASE TRANSFORMERS	100,641
24	NEW BUSINESS RESIDENTIAL - O/H - PINEVILLE	100,634
25	DISTRIBUTION MINOR	4,018,932
26		
27	COMMON MAJOR	
28	SAP FOR CUSTOMER CARE SYSTEM - KU	22,356,920
29	CUSTOMER CARE SYSTEM - TECHNOLOGY KU	5,957,824
30	CUSTOMER CARE SYSTEM - CUSTOMER SERVICE KU	4,211,193
31	LAND MOBILE RADIO SYSTEM BUILDOUT	3,239,664
32	CUSTOMER CARE SYSTEM - DEVELOPMENT KU	1,226,793
33	CUSTOMER CARE SYSTEM - KU BUSINESS INTELLIGENCE	716,216
34	EVA REPLACEMENT PROJECT	486,066
35	TIER C REPLACEMENT KU	384,335
36	EXTEND FIBER TO GREEN RIVER	364,365
37	NORTH KY BACKBONE RENOVATION	340,494
38	COMPUTER TELEPHONE INTEGRATION REPLACEMENT KU	267,260
39	CUSTOMER CARE SYSTEM - CHANGE MANAGEMENT KU	241,834
40	ORACLE FINANCIAL/MATERIAL APPLICATIONS 11.5.10.2 UPGRADE	204,880
41	ORACLE I SUPPORT PORTAL	177,579
42	MISCELLANEOUS KU BUSINESS OFFICE	150,395
43	TOTAL	1,176,440,172

BLANK

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Utilities Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2008/Q4

CONSTRUCTION WORK IN PROGRESS - - ELECTRIC (Account 107)

1. Report below descriptions and balances at end of year of projects in process of construction (107)
2. Show items relating to "research, development, and demonstration" projects last, under a caption Research, Development, and Demonstrating (see Account 107 of the Uniform System of Accounts)
3. Minor projects (5% of the Balance End of the Year for Account 107 or $100,000, whichever is less) may be grouped.

Line No.	Description of Project (a)	Construction work in progress - Electric (Account 107) (b)
1	AVAYA UPGRADES REMOTE KU SYSTEMS	149,553
2	DEVELOP KU CAMPUS NETWORK	148,382
3	KU CARPET AND TILE REPLACEMENT	145,397
4	ACCESS SWITCH ROTATION	144,707
5	SERVER HARDWARE REFRESH	142,649
6	LEXINGTON PURCHASE E-Z HAULER	132,373
7	BACKUP STRATEGY EXPANSION PROJECT	128,632
8	KU INTERNAL REQUESTS	122,366
9	ELIZABETHTOWN STOREROOM PAVING	108,052
10	NAS NETWORK ATTACHED STORAGE	103,333
11	SHELBYVILLE STOREROOM PAVING	102,508
12	COMMON MINOR	3,496,230
13		
14		
15		
16		
17		
18		
19		
20		
21		
22		
23		
24		
25		
26		
27		
28		
29		
30		
31		
32		
33		
34		
35		
36		
37		
38		
39		
40		
41		
42		
43	TOTAL	1,176,440,172

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Utilities Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2008/Q4

ACCUMULATED PROVISION FOR DEPRECIATION OF ELECTRIC UTILITY PLANT (Account 108)

1. Explain in a footnote any important adjustments during year.
2. Explain in a footnote any difference between the amount for book cost of plant retired, Line 11, column (c), and that reported for electric plant in service, pages 204-207, column 9d), excluding retirements of non-depreciable property.
3. The provisions of Account 108 in the Uniform System of accounts require that retirements of depreciable plant be recorded when such plant is removed from service. If the respondent has a significant amount of plant retired at year end which has not been recorded and/or classified to the various reserve functional classifications, make preliminary closing entries to tentatively functionalize the book cost of the plant retired. In addition, include all costs included in retirement work in progress at year end in the appropriate functional classifications.
4. Show separately interest credits under a sinking fund or similar method of depreciation accounting.

Section A. Balances and Changes During Year

Line No.	Item (a)	Total (c+d+e) (b)	Electric Plant in Service (c)	Electric Plant Held for Future Use (d)	Electric Plant Leased to Others (e)
1	Balance Beginning of Year	1,914,631,932	1,914,631,932		
2	Depreciation Provisions for Year, Charged to				
3	(403) Depreciation Expense	130,780,795	130,780,795		
4	(403.1) Depreciation Expense for Asset Retirement Costs	334,214	334,214		
5	(413) Exp. of Elec. Plt. Leas. to Others				
6	Transportation Expenses-Clearing	47,924	47,924		
7	Other Clearing Accounts				
8	Other Accounts (Specify, details in footnote):	-120,346	-252,063	131,717	
9	Fuel Stock	798,145	798,145		
10	TOTAL Deprec. Prov for Year (Enter Total of lines 3 thru 9)	131,840,732	131,709,015	131,717	
11	Net Charges for Plant Retired:				
12	Book Cost of Plant Retired	7,917,559	7,917,559		
13	Cost of Removal	7,152,447	7,152,447		
14	Salvage (Credit)	1,042,194	1,042,194		
15	TOTAL Net Chrgs. for Plant Ret. (Enter Total of lines 12 thru 14)	14,027,812	14,027,812		
16	Other Debit or Cr. Items (Describe, details in footnote):	-2,004,939	-2,004,939		
17					
18	Book Cost or Asset Retirement Costs Retired				
19	Balance End of Year (Enter Totals of lines 1, 10, 15, 16, and 18)	2,030,439,913	2,030,308,196	131,717	
	Section B. Balances at End of Year According to Functional Classification				
20	Steam Production	978,507,043	978,375,326	131,717	
21	Nuclear Production				
22	Hydraulic Production-Conventional	8,216,730	8,216,730		
23	Hydraulic Production-Pumped Storage				
24	Other Production	131,156,517	131,156,517		
25	Transmission	324,822,455	324,822,455		
26	Distribution	534,181,429	534,181,429		
27	Regional Transmission and Market Operation				
28	General	53,555,739	53,555,739		
29	TOTAL (Enter Total of lines 20 thru 28)	2,030,439,913	2,030,308,196	131,717	

Schedule Page: 219 Line No.: 8 Column: c

Accrual for Cost of Removal and ARO Parent assets (FERC 254 and 403)

Schedule Page: 219 Line No.: 8 Column: d

Depreciation reserve for Plant Held for Future Use - Trimble County Cooling Tower (hyperbolic)

Schedule Page: 219 Line No.: 16 Column: c

Customer payments related to construction projects	$(5,886,825)
Net effect of transfers between accounts 107 and 108	3,881,886
Total	$(2,004,939)

BLANK

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Utilities Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2008/Q4

MATERIALS AND SUPPLIES

1. For Account 154, report the amount of plant materials and operating supplies under the primary functional classifications as indicated in column (a); estimates of amounts by function are acceptable. In column (d), designate the department or departments which use the class of material.
2. Give an explanation of important inventory adjustments during the year (in a footnote) showing general classes of material and supplies and the various accounts (operating expenses, clearing accounts, plant, etc.) affected debited or credited. Show separately debit or credits to stores expense clearing, if applicable.

Line No.	Account (a)	Balance Beginning of Year (b)	Balance End of Year (c)	Department or Departments which Use Material (d)
1	Fuel Stock (Account 151)	41,770,628	72,708,035	Electric
2	Fuel Stock Expenses Undistributed (Account 152)			
3	Residuals and Extracted Products (Account 153)			
4	Plant Materials and Operating Supplies (Account 154)			
5	Assigned to - Construction (Estimated)			
6	Assigned to - Operations and Maintenance			
7	Production Plant (Estimated)	17,778,066	19,657,311	Electric
8	Transmission Plant (Estimated)	2,910,358	3,099,200	Electric
9	Distribution Plant (Estimated)	6,681,602	6,805,178	Electric
10	Regional Transmission and Market Operation Plant (Estimated)			
11	Assigned to - Other (provide details in footnote)			
12	TOTAL Account 154 (Enter Total of lines 5 thru 11)	27,370,026	29,561,689	
13	Merchandise (Account 155)			
14	Other Materials and Supplies (Account 156)			
15	Nuclear Materials Held for Sale (Account 157) (Not applic to Gas Util)			
16	Stores Expense Undistributed (Account 163)	6,454,808	6,202,308	Electric
17				
18				
19				
20	TOTAL Materials and Supplies (Per Balance Sheet)	75,595,462	108,472,032	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Utilities Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2008/Q4

Allowances (Accounts 158.1 and 158.2)

1. Report below the particulars (details) called for concerning allowances.
2. Report all acquisitions of allowances at cost.
3. Report allowances in accordance with a weighted average cost allocation method and other accounting as prescribed by General Instruction No. 21 in the Uniform System of Accounts.
4. Report the allowances transactions by the period they are first eligible for use: the current year's allowances in columns (b)-(c), allowances for the three succeeding years in columns (d)-(i), starting with the following year, and allowances for the remaining succeeding years in columns (j)-(k).
5. Report on line 4 the Environmental Protection Agency (EPA) issued allowances. Report withheld portions Lines 36-40.

Line No.	Allowances Inventory (Account 158.1) (a)	Current Year No. (b)	Current Year Amt. (c)	2009 No. (d)	2009 Amt. (e)
1	Balance-Beginning of Year	107,720.00	382,894	105,184.00	
2					
3	Acquired During Year:				
4	Issued (Less Withheld Allow)				
5	Returned by EPA				
6					
7					
8	Purchases/Transfers:				
9	Purchases (see footnote)	502.00	311,495		
10	Transfer from LG&E	66,968.00	3,867		
11	Adjustment to final 2007	32.00			
12					
13					
14					
15	Total	67,502.00	315,362		
16					
17	Relinquished During Year:				
18	Charges to Account 509	161,221.00	619,818		
19	Other:				
20	Charges to 549/158	8,988.00	419		
21	Cost of Sales/Transfers:				
22	Transfer to LG&E	220.00	3,600		
23	Adjustment fo final 2007	171.00			
24					
25					
26					
27					
28	Total	391.00	3,600		
29	Balance-End of Year	4,622.00	74,419	105,184.00	
30					
31	Sales:				
32	Net Sales Proceeds(Assoc. Co.)				
33	Net Sales Proceeds (Other)				
34	Gains				
35	Losses				
	Allowances Withheld (Acct 158.2)				
36	Balance-Beginning of Year	1,109.00		1,109.00	
37	Add: Withheld by EPA				
38	Deduct: Returned by EPA				
39	Cost of Sales	1,109.00			
40	Balance-End of Year			1,109.00	
41					
42	Sales:				
43	Net Sales Proceeds (Assoc. Co.)				
44	Net Sales Proceeds (Other)	1,109.00	432,455		
45	Gains				
46	Losses				

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Utilities Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2008/Q4

Allowances (Accounts 158.1 and 158.2) (Continued)

6. Report on Lines 5 allowances returned by the EPA. Report on Line 39 the EPA's sales of the withheld allowances. Report on Lines 43-46 the net sales proceeds and gains/losses resulting from the EPA's sale or auction of the withheld allowances.
7. Report on Lines 8-14 the names of vendors/transferors of allowances acquire and identify associated companies (See "associated company" under "Definitions" in the Uniform System of Accounts).
8. Report on Lines 22 - 27 the name of purchasers/ transferees of allowances disposed of an identify associated companies.
9. Report the net costs and benefits of hedging transactions on a separate line under purchases/transfers and sales/transfers.
10. Report on Lines 32-35 and 43-46 the net sales proceeds and gains or losses from allowance sales.

2010		2011		Future Years		Totals		Line
No. (f)	Amt. (g)	No. (h)	Amt. (i)	No. (j)	Amt. (k)	No. (l)	Amt. (m)	No.
99,376.00		99,376.00		2,081,433.00		2,493,089.00	382,894	1
								2
								3
				77,535.00		77,535.00		4
								5
								6
								7
								8
						502.00	311,495	9
						66,968.00	3,867	10
						32.00		11
								12
								13
								14
						67,502.00	315,362	15
								16
								17
						161,221.00	619,818	18
								19
						8,988.00	419	20
								21
						220.00	3,600	22
						171.00		23
								24
								25
								26
								27
						391.00	3,600	28
99,376.00		99,376.00		2,158,968.00		2,467,526.00	74,419	29
								30
								31
								32
								33
								34
								35
1,106.50		1,106.50		54,218.50		58,649.50		36
				2,213.00		2,213.00		37
								38
				1,106.50		2,215.50		39
1,106.50		1,106.50		55,325.00		58,647.00		40
								41
								42
								43
				1,106.50	150,652	2,215.50	583,107	44
								45
								46

BLANK

Schedule Page: 228 Line No.: 1 Column: b

The beginning balance allowance amount is composed of 97,723 SO2 allowances and 9,997 Ozone Season NOx allowances.

Schedule Page: 228 Line No.: 1 Column: c

The beginning balance allowance dollars is composed entirely of the value of SO2 allowances.

Schedule Page: 228 Line No.: 1 Column: d

The beginning balance allowance amount is composed of 83,343 SO2 allowances, 6,683 Ozone Season NOx allowances and 15,158 Annual NOx allowances.

Schedule Page: 228 Line No.: 1 Column: f

The beginning balance allowance amount is composed of 77,535 SO2 allowances, 6,683 Ozone Season NOx allowances and 15,158 Annual NOx allowances.

Schedule Page: 228 Line No.: 1 Column: h

The beginning balance allowance amount is composed of 77,535 SO2 allowances, 6,683 Ozone Season NOx allowances and 15,158 Annual NOx allowances.

Schedule Page: 228 Line No.: 1 Column: j

The beginning balance allowance amount is composed of 2,015,910 SO2 allowances, 20,049 Ozone Season NOx allowances and 45,474 Annual NOx allowances.

Schedule Page: 228 Line No.: 1 Column: l

The beginning balance allowance amount is composed of 2,352,046 SO2 allowances, 50,095 Ozone Season NOx allowances and 90,948 Annual NOx allowances.

Schedule Page: 228 Line No.: 1 Column: m

The beginning balance allowance dollars is composed entirely of the value of SO2 allowances.

Schedule Page: 228 Line No.: 9 Column: a

Purchases:

	No.	Cost
Merrill Lynch Commodities NBP	111	$ 70,485
Holcim US Inc	100	61,000
Birchwood Power Facility	30	18,300
Lockport Cogeneration Facility	100	63,500
Bayonne Plant Holding, LLC	36	21,960
Aventine Renewable Energy, Inc	125	76,250
	---	--------
Total	502	$311,495

Schedule Page: 228 Line No.: 10 Column: a

Kentucky Utilities Company and Louisville Gas & Electric Company are both owned by E.ON U.S. LLC.

Schedule Page: 228 Line No.: 22 Column: a

Kentucky Utilities Company and Louisville Gas & Electric Company are both owned by E.ON U.S. LLC.

Name of Respondent Kentucky Utilities Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2008/Q4

OTHER REGULATORY ASSETS (Account 182.3)

1. Report below the particulars (details) called for concerning other regulatory assets, including rate order docket number, if applicable.
2. Minor items (5% of the Balance in Account 182.3 at end of period, or amounts less than $50,000 which ever is less), may be grouped by classes.
3. For Regulatory Assets being amortized, show period of amortization.

Line No.	Description and Purpose of Other Regulatory Assets	Balance at Beginning of Current Quarter/Year	Debits	CREDITS Written off During the Quarter/Year Account Charged	CREDITS Written off During the Period Amount	Balance at end of Current Quarter/Year
	(a)	(b)	(c)	(d)	(e)	(f)
1	SFAS 158 - Pension and Postretirement	27,744,630	99,705,057	228.3	617,597	126,832,090
2	Asset Retirement Obligation	24,116,268	3,771,327	407	16,278	27,871,317
3	MISO Exit Fee	20,097,494		182	1,504,306	18,593,188
4	SFAS 109 - Income Taxes	6,547,298	4,170,072	282/283	510,190	10,207,180
5	FERC Jurisdictional Pension Expenses	2,472,173	340,253			2,812,426
6	Wind Storm 2008		2,188,420			2,188,420
7	Ice Storm (Jul-04 to Jun-09)	1,187,388		593	791,604	395,784
8	Ky Consortium for Carbon Storage		130,014			130,014
9						
10						
11						
12						
13						
14						
15						
16						
17						
18						
19						
20						
21						
22						
23						
24						
25						
26						
27						
28						
29						
30						
31						
32						
33						
34						
35						
36						
37						
38						
39						
40						
41						
42						
43						
44	TOTAL	82,165,251	110,305,143		3,439,975	189,030,419

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Utilities Company	(1) X An Original (2) _ A Resubmission	/ /	2008/Q4

FOOTNOTE DATA

Schedule Page: 232 Line No.: 3 Column: d

Pursuant to FERC Order, Docket No. ER06-1308-004 issued March 4, 2008, adjustments are being made to the beginning balance of the regulatory asset for the MISO exit fee originally paid by the Company in September 2006. These adjustments will continue to be recorded until December 2014.

Name of Respondent Kentucky Utilities Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2008/Q4

MISCELLANEOUS DEFFERED DEBITS (Account 186)

1. Report below the particulars (details) called for concerning miscellaneous deferred debits.
2. For any deferred debit being amortized, show period of amortization in column (a)
3. Minor item (1% of the Balance at End of Year for Account 186 or amounts less than $50,000, whichever is less) may be grouped by classes.

Line No.	Description of Miscellaneous Deferred Debits (a)	Balance at Beginning of Year (b)	Debits (c)	CREDITS Account Charged (d)	CREDITS Amount (e)	Balance at End of Year (f)
1	Key Man Life Insurance	36,870,076	2,560,385	421/426	705,624	38,724,837
2						
3	Environmental Cost Recovery	10,664,697	197,657,102	440-445	188,168,668	20,153,131
4						
5	KY - Fuel Adjustment Clause	16,802,000	28,055,000	440-445	36,987,000	7,870,000
6						
7	OMU Emission Allowances	1,246,600	485,893	555	38,593	1,693,900
8						
9	VA - Fuel Cost Component	528,256	1,503,765	440-445	528,256	1,503,765
10						
11	Rate Case Expenses		1,304,056			1,304,056
12						
13	Financing Expense		1,710,871	181/189	1,316,471	394,400
14						
15	Customer Credit Accounts					
16	Receivable	378,634	3,579,285	440-445	3,772,725	185,194
17						
18	Carrollton Sale/Leaseback					
19	(Aug-06 to Jul-23)	68,750	8,486	961	12,898	64,338
20						
21	Cellular Antenna Billable Chgs	37,091	9,621	456	20,667	26,045
22						
23	Land Options		16,145			16,145
24						
25	Merger Surcredit	691,945	1,025,000	440-445	1,716,945	
26						
27						
28						
29						
30						
31						
32						
33						
34						
35						
36						
37						
38						
39						
40						
41						
42						
43						
44						
45						
46						
47	Misc. Work in Progress	-11,970				91,019
48	Deferred Regulatory Comm. Expenses (See pages 350 - 351)					
49	TOTAL	67,276,079				72,026,830

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Utilities Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2008/Q4

ACCUMULATED DEFERRED INCOME TAXES (Account 190)

1. Report the information called for below concerning the respondent's accounting for deferred income taxes.
2. At Other (Specify), include deferrals relating to other income and deductions.

Line No.	Description and Location (a)	Balance of Begining of Year (b)	Balance at End of Year (c)
1	Electric		
2	Pensions	-5,904,217	-4,975,498
3	Other Post Retirement & Employment Benefits	25,472,518	25,919,571
4	SFAS 109 Regulatory Tax Adjustments	11,006,692	9,629,253
5	SFAS 133	-283,682	
6	SFAS 143	12,886,998	14,185,872
7	Other - See Notes for Detail	7,575,207	5,927,702
8	TOTAL Electric (Enter Total of lines 2 thru 7)	50,753,516	50,686,900
9	Gas		
10			
11			
12			
13			
14			
15	Other		
16	TOTAL Gas (Enter Total of lines 10 thru 15		
17	Other (Specify)		
18	TOTAL (Acct 190) (Total of lines 8, 16 and 17)	50,753,516	50,686,900

Notes

	Bal. at Beg. of Year	Bal. at End of Year
ECR & VA Fuel Clause	(147,674)	(584,965)
Workers' Compensation	1,205,324	1,008,420
Vacation Pay	1,632,212	1,884,363
State Tax Adjustment	765,612	(382,681)
Bad Debt Reserve	754,352	1,119,739
Demand Side Management	702,013	1,965,542
Customer Advances	1,090,498	0
OMU Excess Amortization	751,476	674,373
Other	821,394	242,911
	-----------	----------
Total Electric Line 7	7,575,207	5,927,702
	===========	==========

Balance of Beginning of Year	50,753,516
Less Debits to:	
Acct 410.1	15,109,315
Acct 410.2	447,128
Other Balance Sheet Accounts	3,427,798
Plus Credits to:	
Acct 411.1	18,388,679
Acct 411.2	528,946

Balance at End of Year	50,686,900
	==========

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Utilities Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2008/Q4

CAPITAL STOCKS (Account 201 and 204)

1. Report below the particulars (details) called for concerning common and preferred stock at end of year, distinguishing separate series of any general class. Show separate totals for common and preferred stock. If information to meet the stock exchange reporting requirement outlined in column (a) is available from the SEC 10-K Report Form filing, a specific reference to report form (i.e., year and company title) may be reported in column (a) provided the fiscal years for both the 10-K report and this report are compatible.
2. Entries in column (b) should represent the number of shares authorized by the articles of incorporation as amended to end of year.

Line No.	Class and Series of Stock and Name of Stock Series (a)	Number of shares Authorized by Charter (b)	Par or Stated Value per share (c)	Call Price at End of Year (d)
1	Common Stock			
2	Without Par Value	80,000,000		
3	Total Common	80,000,000		
4				
5	Preferred Stock, Cumulative, $100 Stated Value	5,300,000	100.00	
6	Preference Stock, Without Par Value	2,000,000		
7	Total Preferred	7,300,000	100.00	
8				
9				
10	Note:			
11	There is no Call Price for Common Stock,			
12	Without Par Value			
13				
14	The Common Stock of Kentucky Utilities Company			
15	is owned by its parent company,			
16	E.ON U.S. LLC			
17				
18				
19				
20				
21				
22				
23				
24				
25				
26				
27				
28				
29				
30				
31				
32				
33				
34				
35				
36				
37				
38				
39				
40				
41				
42				

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Utilities Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2008/Q4

CAPITAL STOCKS (Account 201 and 204) (Continued)

3. Give particulars (details) concerning shares of any class and series of stock authorized to be issued by a regulatory commission which have not yet been issued.
4. The identification of each class of preferred stock should show the dividend rate and whether the dividends are cumulative or non-cumulative.
5. State in a footnote if any capital stock which has been nominally issued is nominally outstanding at end of year.
Give particulars (details) in column (a) of any nominally issued capital stock, reacquired stock, or stock in sinking and other funds which is pledged, stating name of pledgee and purposes of pledge.

OUTSTANDING PER BALANCE SHEET (Total amount outstanding without reduction for amounts held by respondent)		HELD BY RESPONDENT				Line No.
		AS REACQUIRED STOCK (Account 217)		IN SINKING AND OTHER FUNDS		
Shares (e)	Amount (f)	Shares (g)	Cost (h)	Shares (i)	Amount (j)	
						1
37,817,878	308,139,978					2
37,817,878	308,139,978					3
						4
						5
						6
						7
						8
						9
						10
						11
						12
						13
						14
						15
						16
						17
						18
						19
						20
						21
						22
						23
						24
						25
						26
						27
						28
						29
						30
						31
						32
						33
						34
						35
						36
						37
						38
						39
						40
						41
						42

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Utilities Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2008/Q4

OTHER PAID-IN CAPITAL (Accounts 208-211, Inc.)

Report below the balance at the end of the year and the information specified below for the respective other paid-in capital accounts. Provide a subheading for each account and show a total for the account, as well as total of all accounts for reconciliation with balance sheet, Page 112. Add more columns for any account if deemed necessary. Explain changes made in any account during the year and give the accounting entries effecting such change.

(a) Donations Received from Stockholders (Account 208)-State amount and give brief explanation of the origin and purpose of each donation.

(b) Reduction in Par or Stated value of Capital Stock (Account 209): State amount and give brief explanation of the capital change which gave rise to amounts reported under this caption including identification with the class and series of stock to which related.

(c) Gain on Resale or Cancellation of Reacquired Capital Stock (Account 210): Report balance at beginning of year, credits, debits, and balance at end of year with a designation of the nature of each credit and debit identified by the class and series of stock to which related.

(d) Miscellaneous Paid-in Capital (Account 211)-Classify amounts included in this account according to captions which, together with brief explanations, disclose the general nature of the transactions which gave rise to the reported amounts.

Line No.	Item (a)	Amount (b)
1		
2	Account 211:	
3	Contributed Capital - Misc. Balance January 1, 2008	90,000,000
4	Contributed Capital March 28, 2008	25,000,000
5	Contributed Capital June 27, 2008	50,000,000
6	Contributed Capital September 29, 2008	50,000,000
7	Contributed Capital December 26, 2008	20,000,000
8	Contributed Capital December 31, 2008	5,711,597
9		
10		
11		
12		
13		
14		
15		
16		
17		
18		
19		
20		
21		
22		
23		
24		
25		
26		
27		
28		
29		
30		
31		
32		
33		
34		
35		
36		
37		
38		
39		
40	TOTAL	240,711,597

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Utilities Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2008/Q4

CAPITAL STOCK EXPENSE (Account 214)

1. Report the balance at end of the year of discount on capital stock for each class and series of capital stock.
2. If any change occurred during the year in the balance in respect to any class or series of stock, attach a statement giving particulars (details) of the change. State the reason for any charge-off of capital stock expense and specify the account charged.

Line No.	Class and Series of Stock (a)	Balance at End of Year (b)
1	Expenses on Common Stock	321,289
2		
3		
4		
5		
6		
7		
8		
9		
10		
11		
12		
13		
14		
15		
16		
17		
18		
19		
20		
21		
22	TOTAL	321,289

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Utilities Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2008/Q4

LONG-TERM DEBT (Account 221, 222, 223 and 224)

1. Report by balance sheet account the particulars (details) concerning long-term debt included in Accounts 221, Bonds, 222, Reacquired Bonds, 223, Advances from Associated Companies, and 224, Other long-Term Debt.
2. In column (a), for new issues, give Commission authorization numbers and dates.
3. For bonds assumed by the respondent, include in column (a) the name of the issuing company as well as a description of the bonds.
4. For advances from Associated Companies, report separately advances on notes and advances on open accounts. Designate demand notes as such. Include in column (a) names of associated companies from which advances were received.
5. For receivers, certificates, show in column (a) the name of the court -and date of court order under which such certificates were issued.
6. In column (b) show the principal amount of bonds or other long-term debt originally issued.
7. In column (c) show the expense, premium or discount with respect to the amount of bonds or other long-term debt originally issued.
8. For column (c) the total expenses should be listed first for each issuance, then the amount of premium (in parentheses) or discount. Indicate the premium or discount with a notation, such as (P) or (D). The expenses, premium or discount should not be netted.
9. Furnish in a footnote particulars (details) regarding the treatment of unamortized debt expense, premium or discount associated with issues redeemed during the year. Also, give in a footnote the date of the Commission's authorization of treatment other than as specified by the Uniform System of Accounts.

Line No.	Class and Series of Obligation, Coupon Rate (For new issue, give commission Authorization numbers and dates) (a)	Principal Amount Of Debt issued (b)	Total expense, Premium or Discount (c)
1	ACCOUNT 221:		
2	Pollution Control Bonds: (2)		
3	Mercer County 2000 Series A, due 05/01/2023, Variable (3)	12,900,000	497,122
4	Carroll County 2002 Series A, due 02/01/2032, Variable	20,930,000	120,138
5	Carroll County 2002 Series B, due 02/01/2032, Variable	2,400,000	83,078
6	Muhlenberg County 2002 Series A, due 02/01/2032, Variable	2,400,000	93,078
7	Mercer County 2002 Series A, due 02/01/2032, Variable	7,400,000	92,678
8	Carroll County 2002 Series C, due 10/01/2032, Variable	96,000,000	2,131,476
9	Carroll County 2004 Series A, due 10/01/2034, Variable (3)	50,000,000	1,363,166
10	Carroll County 2005 Series A, due 06/01/2035, Variable (defeased 11/5/08) (3)(4)	13,266,950	529,682
11	Carroll County 2005 Series B, due 06/01/2035, Variable (defeased 11/5/08) (3)(4)	13,266,950	533,187
12	Carroll County 2006 Series A, due 06/01/2036, Variable (defeased 11/12/08) (3)(4)	16,693,620	618,873
13	Carroll County 2006 Series B, due 10/01/2034, Variable (3)	54,000,000	1,213,518
14	Carroll County 2006 Series C, due 06/01/2036, Variable (defeased 10/17/08) (3)(4)	16,693,620	629,606
15	Carroll County 2007 Series A, due 02/01/2026, 5.750% (3)	17,875,000	610,016
16	Trimble County 2007 Series A, due 03/01/2037, 6.000% (3)	8,927,000	456,138
17	Carroll County 2008 Series A, due 02/01/2032, Variable (3)(4)	77,947,405	545,471
18	TOTAL ACCOUNT 221	410,700,545	9,517,227
19			
20	ACCOUNT 223:		
21	Notes Payable to Fidelia, due 11/24/2010, 4.240% - unsecured	33,000,000	
22	Notes Payable to Fidelia, due 01/16/2012, 4.390% - unsecured	50,000,000	
23	Notes Payable to Fidelia, due 04/30/2013, 4.550% - unsecured	100,000,000	
24	Notes Payable to Fidelia, due 08/15/2013, 5.310% - unsecured	75,000,000	
25	Notes Payable to Fidelia, due 12/19/2014, 5.450% - unsecured	100,000,000	
26	Notes Payable to Fidelia, due 07/08/2015, 4.735% - unsecured	50,000,000	
27	Notes Payable to Fidelia, due 12/21/2015, 5.360% - unsecured	75,000,000	
28	Notes Payable to Fidelia, due 10/26/2016, 5.675% - unsecured	50,000,000	
29	Notes Payable to Fidelia, due 06/20/2017, 5.980% - unsecured	50,000,000	
30	Notes Payable to Fidelia, due 07/25/2018, 6.160% - unsecured (5)	50,000,000	
31	Notes Payable to Fidelia, due 08/27/2018, 5.645% - unsecured (5)	50,000,000	
32	Notes Payable to Fidelia, due 12/17/2018, 7.035% - unsecured (5)	75,000,000	
33	TOTAL	1,591,700,545	9,517,227

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Utilities Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2008/Q4

LONG-TERM DEBT (Account 221, 222, 223 and 224) (Continued)

10. Identify separate undisposed amounts applicable to issues which were redeemed in prior years.
11. Explain any debits and credits other than debited to Account 428, Amortization and Expense, or credited to Account 429, Premium on Debt - Credit.
12. In a footnote, give explanatory (details) for Accounts 223 and 224 of net changes during the year. With respect to long-term advances, show for each company: (a) principal advanced during year, (b) interest added to principal amount, and (c) principle repaid during year. Give Commission authorization numbers and dates.
13. If the respondent has pledged any of its long-term debt securities give particulars (details) in a footnote including name of pledgee and purpose of the pledge.
14. If the respondent has any long-term debt securities which have been nominally issued and are nominally outstanding at end of year, describe such securities in a footnote.
15. If interest expense was incurred during the year on any obligations retired or reacquired before end of year, include such interest expense in column (i). Explain in a footnote any difference between the total of column (i) and the total of Account 427, interest on Long-Term Debt and Account 430, Interest on Debt to Associated Companies.
16. Give particulars (details) concerning any long-term debt authorized by a regulatory commission but not yet issued.

Nominal Date of Issue (d)	Date of Maturity (e)	AMORTIZATION PERIOD Date From (f)	AMORTIZATION PERIOD Date To (g)	Outstanding (Total amount outstanding without reduction for amounts held by respondent) (h)	Interest for Year Amount (i)	Line No.
						1
						2
05/19/2000	05/01/2023	05/19/2000	05/01/2023	12,900,000	295,138	3
05/23/2002	02/01/2032	05/23/2002	02/01/2032	20,930,000	384,152	4
05/23/2002	02/01/2032	05/23/2002	02/01/2032	2,400,000	44,050	5
05/23/2002	02/01/2032	05/23/2002	02/01/2032	2,400,000	44,050	6
05/23/2002	02/01/2032	05/23/2002	02/01/2032	7,400,000	135,821	7
10/03/2002	10/01/2032	10/03/2002	10/01/2032	96,000,000	3,562,336	8
10/20/2004	10/01/2034	10/20/2004	10/01/2034	50,000,000	1,550,362	9
07/07/2005	06/01/2035	07/07/2005	06/01/2035		443,854	10
11/17/2005	06/01/2035	11/17/2005	06/01/2035		442,897	11
07/20/2006	06/01/2036	07/20/2006	06/01/2036		831,961	12
02/23/2007	10/01/2034	02/23/2007	10/01/2034	54,000,000	2,885,164	13
12/07/2006	06/01/2036	12/07/2006	06/01/2036		338,340	14
05/24/2007	02/01/2026	05/24/2007	02/01/2026	17,875,000	985,687	15
05/24/2007	03/01/2037	05/24/2007	03/01/2037	8,927,000	508,941	16
10/17/2008	02/01/2032	10/17/2008	02/01/2032	77,947,405	325,420	17
				350,779,405	12,778,173	18
						19
						20
11/24/2003	11/24/2010			33,000,000	1,399,200	21
01/15/2004	01/16/2012			50,000,000	2,195,000	22
04/30/2003	04/30/2013			100,000,000	4,550,000	23
08/15/2003	08/15/2013			75,000,000	3,982,500	24
12/20/2007	12/19/2014			100,000,000	5,450,000	25
07/08/2005	07/08/2015			50,000,000	2,367,500	26
12/19/2005	12/21/2015			75,000,000	4,020,000	27
10/25/2006	10/25/2016			50,000,000	2,837,500	28
06/20/2007	06/20/2017			50,000,000	2,990,000	29
07/25/2008	07/25/2018			50,000,000	1,334,667	30
08/26/2008	08/27/2018			50,000,000	980,035	31
12/15/2008	12/17/2018			75,000,000	219,844	32
				1,531,779,405	68,330,556	33

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Utilities Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2008/Q4

LONG-TERM DEBT (Account 221, 222, 223 and 224)

1. Report by balance sheet account the particulars (details) concerning long-term debt included in Accounts 221, Bonds, 222, Reacquired Bonds, 223, Advances from Associated Companies, and 224, Other long-Term Debt.
2. In column (a), for new issues, give Commission authorization numbers and dates.
3. For bonds assumed by the respondent, include in column (a) the name of the issuing company as well as a description of the bonds.
4. For advances from Associated Companies, report separately advances on notes and advances on open accounts. Designate demand notes as such. Include in column (a) names of associated companies from which advances were received.
5. For receivers, certificates, show in column (a) the name of the court -and date of court order under which such certificates were issued.
6. In column (b) show the principal amount of bonds or other long-term debt originally issued.
7. In column (c) show the expense, premium or discount with respect to the amount of bonds or other long-term debt originally issued.
8. For column (c) the total expenses should be listed first for each issuance, then the amount of premium (in parentheses) or discount. Indicate the premium or discount with a notation, such as (P) or (D). The expenses, premium or discount should not be netted.
9. Furnish in a footnote particulars (details) regarding the treatment of unamortized debt expense, premium or discount associated with issues redeemed during the year. Also, give in a footnote the date of the Commission's authorization of treatment other than as specified by the Uniform System of Accounts.

Line No.	Class and Series of Obligation, Coupon Rate (For new issue, give commission Authorization numbers and dates) (a)	Principal Amount Of Debt issued (b)	Total expense, Premium or Discount (c)
1	ACCOUNT 223 continued:		
2	Notes Payable to Fidelia, due 10/25/2019, 5.710% - unsecured	70,000,000	
3	Notes Payable to Fidelia, due 02/07/2022, 5.690% - unsecured	53,000,000	
4	Notes Payable to Fidelia, due 05/22/2023, 5.850% - unsecured (5)	75,000,000	
5	Notes Payable to Fidelia, due 09/14/2028, 5.960% - unsecured (5)	100,000,000	
6	Notes Payable to Fidelia, due 06/23/2036, 6.330% - unsecured (5)	50,000,000	
7	Notes Payable to Fidelia, due 03/30/2037, 5.860% - unsecured (5)	75,000,000	
8	TOTAL ACCOUNT 223	1,181,000,000	
9			
10			
11			
12			
13			
14			
15			
16			
17			
18			
19			
20			
21			
22			
23			
24			
25			
26			
27			
28			
29			
30			
31			
32			
33	TOTAL	1,591,700,545	9,517,227

Name of Respondent Kentucky Utilities Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2008/Q4

LONG-TERM DEBT (Account 221, 222, 223 and 224) (Continued)

10. Identify separate undisposed amounts applicable to issues which were redeemed in prior years.
11. Explain any debits and credits other than debited to Account 428, Amortization and Expense, or credited to Account 429, Premium on Debt - Credit.
12. In a footnote, give explanatory (details) for Accounts 223 and 224 of net changes during the year. With respect to long-term advances, show for each company: (a) principal advanced during year, (b) interest added to principal amount, and (c) principle repaid during year. Give Commission authorization numbers and dates.
13. If the respondent has pledged any of its long-term debt securities give particulars (details) in a footnote including name of pledgee and purpose of the pledge.
14. If the respondent has any long-term debt securities which have been nominally issued and are nominally outstanding at end of year, describe such securities in a footnote.
15. If interest expense was incurred during the year on any obligations retired or reacquired before end of year, include such interest expense in column (i). Explain in a footnote any difference between the total of column (i) and the total of Account 427, interest on Long-Term Debt and Account 430, Interest on Debt to Associated Companies.
16. Give particulars (details) concerning any long-term debt authorized by a regulatory commission but not yet issued.

Nominal Date of Issue (d)	Date of Maturity (e)	AMORTIZATION PERIOD Date From (f)	AMORTIZATION PERIOD Date To (g)	Outstanding (Total amount outstanding without reduction for amounts held by respondent) (h)	Interest for Year Amount (i)	Line No.
						1
10/25/2007	10/25/2019			70,000,000	3,997,000	2
02/07/2007	02/07/2022			53,000,000	3,015,700	3
05/20/2008	05/22/2023			75,000,000	2,693,437	4
09/14/2007	09/14/2028			100,000,000	5,960,000	5
06/23/2006	06/23/2036			50,000,000	3,165,000	6
03/30/2007	03/30/2037			75,000,000	4,395,000	7
				1,181,000,000	55,552,383	8
						9
						10
						11
						12
						13
						14
						15
						16
						17
						18
						19
						20
						21
						22
						23
						24
						25
						26
						27
						28
						29
						30
						31
						32
				1,531,779,405	68,330,556	33

Schedule Page: 256 Line No.: 1 Column: a

(1) Per instruction 9 concerning the treatment of unamortized debt expense, premium or discount - Debt premium and expenses are being amortized over the lives of the related issues.

(2) Pollution control series bonds are obligations of Kentucky Utilities Company (KU) issued in connection with tax-exempt pollution control revenue bonds issued by various governmental entities, principally counties in Kentucky. A loan agreement obligates KU to make debt service payments to the county that equate to the debt service due from the county on the related pollution control revenue bonds.

(3) In February 2008, KU issued a notice to bondholders of its intention to convert the Carroll County 2007 Series A bond and the Trimble County 2007 Series A bond from the auction rate mode to a fixed interest rate mode, as permitted under the loan documents. These conversions were completed in April 2008, and the new rates on the bonds are 5.75% and 6.00%, respectively.

In March 2008, KU issued notices to bondholders of its intention to convert the Carroll County 2006 Series C bond and the Mercer County 2000 Series A bond from the auction rate mode to a weekly interest rate mode, as permitted under the loan documents. The Carroll County conversion was completed in April 2008, and the Mercer County conversion was completed in May 2008. In connection with these conversions, KU purchased the bonds from the remarketing agent. In October 2008, the Carroll County 2006 Series C bond, along with the Carroll County 2005 Series A and B and Carroll County 2006 Series A bonds, were defeased.

In June 2008, KU issued notices to bondholders of its intention to convert the Carroll County 2004 Series A bond from the auction rate mode to a weekly interest rate mode, as permitted under the loan documents. The conversion was completed in July 2008. In connection with the conversion, KU purchased the bond from the remarketing agent.

In November 2008, KU issued notices to bondholders of its intention to convert the Carroll County 2006 Series B and Carroll County 2008 Series A bonds from the auction rate mode to a weekly interest rate mode, as permitted under the loan documents. The conversion was completed in December 2008. In connection with the conversions, the bond insurance policy associated with the bonds was terminated and replaced with letters of credit.

In December 2008, KU remarketed the Mercer County 2000 Series A and Carroll County 2004 Series A bonds. In connection with the conversions, the bond insurance policy associated with the bonds was terminated and replaced with letters of credit.

In December, KU converted the interest rate mode of the Carroll County 2006 Series B to a weekly mode from an auction mode. The bond along with the Carroll County 2004 Series A, the Mercer County 2000 Series A, and the Carroll County 2008 Series A, were issued with the enhancement of a letter of credit.

As of December 31, 2008, KU had no remaining repurchased bonds.

(4) In October 2008, KU issued Carroll County 2008 Series A tax exempt bond in the amount of $78 million as authorized by the Kentucky Public Serice Commission in its orders dated September 16, 2008 in Case No. 2008-00309 and June 17, 2008 in Case No. 2008-00132, the Commonwealth of Virginia State Corporation Commission in its orders dated August 29, 2008 is Case No. PUE-2008-00077 and June 19, 2008 in Case No. PUE-2008-00034, and the Tennessee Regulatory Authority in its orders dated September 15, 2008 in Case No 08-00144 and July 15, 2008 in Case No. 08-00070. The new bond matures on February 1, 2032, and bears interest at a variable rate. The new bond refinanced four existing bonds (Carroll County 2005 Series A and B - $13 million each and the Carroll County 2006 Series A and C - $17 million each), and includes $18 million of new funding. The proceeds from the new funding

will be held in escrow pending incurrence of qualifying expenditures.

(5) During 2008, the Company executed four additional long-term loans with Fidelia Corporation:

Amount	Interest Rate	Date Issued	Maturity Date
$75,000,000	5.850%	05/20/2008	05/22/2023
$50,000,000	6.160%	07/25/2008	07/25/2018
$50,000,000	5.645%	08/26/2008	08/27/2018
$75,000,000	7.035%	12/15/2008	12/17/2018

The new long-term loan agreements were authorized by the Kentucky Public Serive Commission in its February 13, 2008 Order in Case No. 2007-00548, the Commonwealth of Virginia State Corporation Commission in its January 16, 2008 Order in Case No. PUE-2007-00118, and the Tennessee Regulatory Authority in its February 22, 2008 Order in Case No. 08-00009.

Schedule Page: 256 Line No.: 1 Column: i

Interest Pollution Control Bonds (221):	
Total Account 427000-427199	$12,778,173
Interest on Debt to Associated Companies:	
Notes Payable (223)	55,552,383
Other Short Term Interest	2,307,256
Total Account 430	$57,859,639

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Utilities Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2008/Q4

RECONCILIATION OF REPORTED NET INCOME WITH TAXABLE INCOME FOR FEDERAL INCOME TAXES

1. Report the reconciliation of reported net income for the year with taxable income used in computing Federal income tax accruals and show computation of such tax accruals. Include in the reconciliation, as far as practicable, the same detail as furnished on Schedule M-1 of the tax return for the year. Submit a reconciliation even though there is no taxable income for the year. Indicate clearly the nature of each reconciling amount.
2. If the utility is a member of a group which files a consolidated Federal tax return, reconcile reported net income with taxable net income as if a separate return were to be field, indicating, however, intercompany amounts to be eliminated in such a consolidated return. State names of group member, tax assigned to each group member, and basis of allocation, assignment, or sharing of the consolidated tax among the group members.
3. A substitute page, designed to meet a particular need of a company, may be used as Long as the data is consistent and meets the requirements of the above instructions. For electronic reporting purposes complete Line 27 and provide the substitute Page in the context of a footnote.

Line No.	Particulars (Details) (a)	Amount (b)
1	Net Income for the Year (Page 117)	157,265,567
2		
3		
4	Taxable Income Not Reported on Books	
5	See footnote	3,000,000
6		
7		
8		
9	Deductions Recorded on Books Not Deducted for Return	
10	See footnote	141,845,158
11		
12		
13		
14	Income Recorded on Books Not Included in Return	
15	See footnote	25,243,762
16		
17		
18		
19	Deductions on Return Not Charged Against Book Income	
20	See footnote	79,471,049
21		
22		
23		
24		
25		
26		
27	Federal Tax Net Income	197,395,914
28	Show Computation of Tax:	
29		
30	Federal Tax Net Income	197,395,914
31	35% Rounded	69,088,570
32	Add: Adjustments of Prior Years' Taxes to Actual and Other	1,658,727
33	Add: Investment Tax Credits	-25,266,898
34		
35	Total	45,480,399
36		
37		
38		
39		
40		
41		
42		
43		
44		

Schedule Page: 261 Line No.: 5 Column: b

Contributions in Aid of Construction	3,000,000

	3,000,000
	==========

Schedule Page: 261 Line No.: 10 Column: b

Federal Income Taxes:	
Utility Operating Income	43,184,629
Other Income and Deductions	2,295,770
Pensions	3,222,999
SFAS 106 Postretirement	796,806
Investment Tax Credit	25,266,898
Capitalized Interest	51,764,542
Demand Side Management	3,248,143
MISO Exit Fees	5,435,476
Bad Debt Reserves	939,297
Vacation Pay	362,607
Environmental Assessment	200,000
EEI Investment	1,898,903
Non-Deductible Expenses	1,141,838
Other	2,087,250

	141,845,158
	===========

Schedule Page: 261 Line No.: 15 Column: b

Equity in Subsidiary Earnings - EEI	24,000,000
Fuel Adjustment Clause KY & VA	556,434
Amortization of Investment Tax Credit	314,308
Customer Advances for Construction	373,020

	25,243,762
	==========

Schedule Page: 261 Line No.: 20 Column: b

Tax over Book Depreciation, Net	42,691,546
Loss on Reacquired Debt, Net of Amortization	3,047,945
Over/Under Collections - VA	975,509
Amortization of Regulatory Expenses	612,112
Workers Compensation	506,179
Mark to Market	833,146
Current State Income Tax	1,093,372
Provision for Deferred Income Taxes	12,770,271
Storm Damages	1,396,816
AFUDC	5,481,085
Life Insurance	1,854,761
IRC 199 Manufacturing Deduction	7,377,362
Other	830,945

	79,471,049
	==========

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Utilities Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2008/Q4

TAXES ACCRUED, PREPAID AND CHARGED DURING YEAR

1. Give particulars (details) of the combined prepaid and accrued tax accounts and show the total taxes charged to operations and other accounts during the year. Do not include gasoline and other sales taxes which have been charged to the accounts to which the taxed material was charged. If the actual, or estimated amounts of such taxes are know, show the amounts in a footnote and designate whether estimated or actual amounts.
2. Include on this page, taxes paid during the year and charged direct to final accounts, (not charged to prepaid or accrued taxes.) Enter the amounts in both columns (d) and (e). The balancing of this page is not affected by the inclusion of these taxes.
3. Include in column (d) taxes charged during the year, taxes charged to operations and other accounts through (a) accruals credited to taxes accrued, (b)amounts credited to proportions of prepaid taxes chargeable to current year, and (c) taxes paid and charged direct to operations or accounts other than accrued and prepaid tax accounts.
4. List the aggregate of each kind of tax in such manner that the total tax for each State and subdivision can readily be ascertained.

Line No.	Kind of Tax (See instruction 5) (a)	BALANCE AT BEGINNING OF YEAR Taxes Accrued (Account 236) (b)	Prepaid Taxes (Include in Account 165) (c)	Taxes Charged During Year (d)	Taxes Paid During Year (e)	Adjust-ments (f)
1	Federal:					
2	Income	5,097,780		46,089,384	40,445,355	
3	FICA	497,417		5,634,374	5,578,342	
4	FIN 48	456,000		-456,000		
5						
6	Kentucky:					
7	Income	1,103,850		8,161,454	9,254,826	
8	Public Service Commission		895,258	1,791,634	1,792,751	
9	Sales & Use	618,308		3,967,830	4,008,265	
10	Auto License			88,312	88,312	
11						
12	Federal & Kentucky:					
13	Unemployment Insurance	36,767		115,702	104,150	
14						
15	Kentucky & Local:					
16	Property Taxes	6,474,647		12,901,622	12,554,077	
17	Vehicle Tax					
18	Miscellaneous					
19						
20						
21						
22						
23						
24						
25						
26						
27						
28						
29						
30						
31						
32						
33						
34						
35						
36						
37						
38						
39						
40						
41	TOTAL	4,089,209	895,258	78,294,312	73,826,078	

Name of Respondent Kentucky Utilities Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2008/Q4

TAXES ACCRUED, PREPAID AND CHARGED DURING YEAR (Continued)

5. If any tax (exclude Federal and State income taxes)- covers more then one year, show the required information separately for each tax year, identifying the year in column (a).
6. Enter all adjustments of the accrued and prepaid tax accounts in column (f) and explain each adjustment in a foot- note. Designate debit adjustments by parentheses.
7. Do not include on this page entries with respect to deferred income taxes or taxes collected through payroll deductions or otherwise pending transmittal of such taxes to the taxing authority.
8. Report in columns (i) through (l) how the taxes were distributed. Report in column (l) only the amounts charged to Accounts 408.1 and 409.1 pertaining to electric operations. Report in column (l) the amounts charged to Accounts 408.1 and 109.1 pertaining to other utility departments and amounts charged to Accounts 408.2 and 409.2. Also shown in column (l) the taxes charged to utility plant or other balance sheet accounts.
9. For any tax apportioned to more than one utility department or account, state in a footnote the basis (necessity) of apportioning such tax.

BALANCE AT END OF YEAR		DISTRIBUTION OF TAXES CHARGED				
(Taxes accrued Account 236) (g)	Prepaid Taxes (Incl. in Account 165) (h)	Electric (Account 408.1, 409.1) (i)	Extraordinary Items (Account 409.3) (j)	Adjustments to Ret. Earnings (Account 439) (k)	Other (l)	Line No.
						1
546,249		43,184,629			2,904,755	2
553,449		6,141,815			-507,441	3
					-456,000	4
						5
						6
10,478		10,053,734			-1,892,280	7
	896,375	1,791,634				8
577,873		36,593			3,931,237	9
					88,312	10
						11
						12
48,319		179,929			-64,227	13
						14
						15
6,822,192		12,471,198			430,424	16
		34,453			-34,453	17
		5,472			-5,472	18
						19
						20
						21
						22
						23
						24
						25
						26
						27
						28
						29
						30
						31
						32
						33
						34
						35
						36
						37
						38
						39
						40
8,558,560	896,375	73,899,457			4,394,855	41

BLANK

Schedule Page: 262 Line No.: 1 Column: l

Segregation of Other	col 1 Other	Page 117 Other Inc & Deductions 408.2 - 409.2	Other Accounts
Federal:			
Income	2,904,755	2,295,770	608,985
FICA	(507,441)		(507,441)
FIN 48	(456,000)		(456,000)
Kentucky:			
Income	(1,892,280)	224,373	(2,116,653)
6% Use	3,931,237		3,931,237
Auto License	88,312		88,312
Federal & Kentucky:			
Unemployment Ins	(64,227)		(64,227)
Kentucky & Local:			
Property Taxes	430,424	9,625	420,799
Federal, State & Local:			
Vehicle Tax	(34,453)		(34,453)
Miscellaneous	(5,472)		(5,472)
Total	4,394,855	2,529,768	1,865,087

Reconciliation to page 114, line 14:

Other:	
Electric Total	73,899,457
Less Federal	(43,184,629)
Less State	(10,053,734)
	20,661,094

Schedule Page: 262 Line No.: 2 Column: b

The balance of ($5,097,780) for Federal income taxes accrued at 12/31/07 reflects an overpayment of Federal income taxes.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Utilities Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2008/Q4

ACCUMULATED DEFERRED INVESTMENT TAX CREDITS (Account 255)

Report below information applicable to Account 255. Where appropriate, segregate the balances and transactions by utility and nonutility operations. Explain by footnote any correction adjustments to the account balance shown in column (g).Include in column (i) the average period over which the tax credits are amortized.

Line No.	Account Subdivisions (a)	Balance at Beginning of Year (b)	Deferred for Year		Allocations to Current Year's Income		Adjustments (g)
			Account No. (c)	Amount (d)	Account No. (e)	Amount (f)	
1	Electric Utility						
2	3%						
3	4%						
4	7%						
5	10%						
6	8%	432,465			420	314,308	
7	15%	54,566,647	411.4	25,266,898			
8	TOTAL	54,999,112		25,266,898		314,308	
9	Other (List separately and show 3%, 4%, 7%, 10% and TOTAL)						
10							
11							
12							
13							
14							
15							
16							
17							
18							
19							
20							
21							
22							
23							
24							
25							
26							
27							
28							
30							
31							
32							
33							
34							
35							
36							
37							
38							
39							
40							
41							
42							
43							
44							
45							
46							
47							
48							

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Utilities Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2008/Q4

ACCUMULATED DEFERRED INVESTMENT TAX CREDITS (Account 255) (continued)

Balance at End of Year (h)	Average Period of Allocation to Income (i)	ADJUSTMENT EXPLANATION	Line No.
			1
			2
			3
			4
			5
118,157	25 years		6
79,833,545	37 years		7
79,951,702			8
			9
			10
			11
			12
			13
			14
			15
			16
			17
			18
			19
			20
			21
			22
			23
			24
			25
			26
			27
			28
			30
			31
			32
			33
			34
			35
			36
			37
			38
			39
			40
			41
			42
			43
			44
			45
			46
			47
			48

BLANK

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Utilities Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2008/Q4

OTHER DEFFERED CREDITS (Account 253)

1. Report below the particulars (details) called for concerning other deferred credits.
2. For any deferred credit being amortized, show the period of amortization.
3. Minor items (5% of the Balance End of Year for Account 253 or amounts less than $10,000, whichever is greater) may be grouped by classes.

Line No.	Description and Other Deferred Credits (a)	Balance at Beginning of Year (b)	DEBITS Contra Account (c)	DEBITS Amount (d)	Credits (e)	Balance at End of Year (f)
1	Brown CT Long-Term Service					
2	Agreement	7,638,225	232	730,208	5,992,014	12,900,031
3						
4	Demand Side Management -		908			
5	Refundable Costs	1,804,664	186/440-445	18,293,354	21,541,496	5,052,806
6						
7	Other Def Credits - OMU Excess					
8	(Jan-04 to Nov-19)	1,931,815	555	198,209		1,733,606
9						
10	KU-EKPC Settlement	1,529,440	232	382,360		1,147,080
11						
12	Deferred Compensation	451,707			27,451	479,158
13						
14	Uncertain Tax Position - Federal		409	456,000	666,000	210,000
15						
16	Merger Surcredit				66,000	66,000
17						
18	Carrollton Sale/Leaseback					
19	(Aug-06 to Jul-23)	68,271	421	4,381		63,890
20						
21	Uncertain Tax Position - State				36,000	36,000
22						
23	Def. Rent Payable					
24	(Aug-06 to Jul-23)	12,022	186	4,412	12,898	20,508
25						
26						
27						
28						
29						
30						
31						
32						
33						
34						
35						
36						
37						
38						
39						
40						
41						
42						
43						
44						
45						
46						
47	TOTAL	13,436,144		20,068,924	28,341,859	21,709,079

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Utilities Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2008/Q4

ACCUMULATED DEFFERED INCOME TAXES - OTHER PROPERTY (Account 282)

1. Report the information called for below concerning the respondent's accounting for deferred income taxes rating to property not subject to accelerated amortization
2. For other (Specify),include deferrals relating to other income and deductions.

Line No.	Account (a)	Balance at Beginning of Year (b)	CHANGES DURING YEAR Amounts Debited to Account 410.1 (c)	CHANGES DURING YEAR Amounts Credited to Account 411.1 (d)
1	Account 282			
2	Electric	291,507,115	21,817,662	31,536,209
3	Gas			
4				
5	TOTAL (Enter Total of lines 2 thru 4)	291,507,115	21,817,662	31,536,209
6				
7				
8				
9	TOTAL Account 282 (Enter Total of lines 5 thru	291,507,115	21,817,662	31,536,209
10	Classification of TOTAL			
11	Federal Income Tax	252,031,721	19,915,741	27,094,916
12	State Income Tax	39,475,394	1,901,921	4,441,293
13	Local Income Tax			

NOTES

Name of Respondent Kentucky Utilities Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2008/Q4

ACCUMULATED DEFERRED INCOME TAXES - OTHER PROPERTY (Account 282) (Continued)

3. Use footnotes as required.

CHANGES DURING YEAR		ADJUSTMENTS					
		Debits		Credits			
Amounts Debited to Account 410.2 (e)	Amounts Credited to Account 411.2 (f)	Account Credited (g)	Amount (h)	Account Debited (i)	Amount (j)	Balance at End of Year (k)	Line No.
							1
		182/190	216,318	182	2,247,245	283,819,495	2
							3
							4
			216,318		2,247,245	283,819,495	5
							6
							7
							8
			216,318		2,247,245	283,819,495	9
							10
			216,318		1,690,547	246,326,775	11
					556,698	37,492,720	12
							13

NOTES (Continued)

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Utilities Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2008/Q4

ACCUMULATED DEFFERED INCOME TAXES - OTHER (Account 283)

1. Report the information called for below concerning the respondent's accounting for deferred income taxes relating to amounts recorded in Account 283.
2. For other (Specify),include deferrals relating to other income and deductions.

Line No.	Account (a)	Balance at Beginning of Year (b)	CHANGES DURING YEAR Amounts Debited to Account 410.1 (c)	Amounts Credited to Account 411.1 (d)
1	Account 283			
2	Electric			
3	OMU & Other Emission Allowance	632,983	57,854	2,963
4	Loss on Reacquired Debt	3,957,556	1,390,768	205,117
5	SFAS 143	9,529,693	11,479	588
6	FAC Under-Recovery	10,742,362	4,910,737	4,694,285
7	MISO Exit Fees	5,778,944	114,139	2,228,527
8	Other	2,898,577	3,036,176	1,339,207
9	TOTAL Electric (Total of lines 3 thru 8)	33,540,115	9,521,153	8,470,687
10	Gas			
11				
12				
13				
14				
15				
16				
17	TOTAL Gas (Total of lines 11 thru 16)			
18	Other	8,249,551	1,588,465	2,993,399
19	TOTAL (Acct 283) (Enter Total of lines 9, 17 and 18)	41,789,666	11,109,618	11,464,086
20	Classification of TOTAL			
21	Federal Income Tax	35,317,690	9,467,977	9,870,553
22	State Income Tax	6,471,976	1,641,641	1,593,533
23	Local Income Tax			

NOTES

Name of Respondent Kentucky Utilities Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2008/Q4

ACCUMULATED DEFERRED INCOME TAXES - OTHER (Account 283) (Continued)

3. Provide in the space below explanations for Page 276 and 277. Include amounts relating to insignificant items listed under Other.
4. Use footnotes as required.

CHANGES DURING YEAR		ADJUSTMENTS					
		Debits		Credits			
Amounts Debited to Account 410.2 (e)	Amounts Credited to Account 411.2 (f)	Account Credited (g)	Amount (h)	Account Debited (i)	Amount (j)	Balance at End of Year (k)	Line No.
[redacted]							1
[redacted]							2
						687,874	3
						5,143,207	4
		190	148,465			9,392,119	5
		190	57,817			10,900,997	6
						3,664,556	7
		182/190	201,579	182/190	1,695,271	6,089,238	8
			407,861		1,695,271	35,877,991	9
[redacted]							10
							11
							12
							13
							14
							15
							16
							17
669,421	5,497					7,508,541	18
669,421	5,497		407,861		1,695,271	43,386,532	19
[redacted]							20
566,656	2,617				1,520,400	36,999,553	21
102,765	2,880		407,861		174,871	6,386,979	22
							23

NOTES (Continued)

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Utilities Company	(1) X An Original (2) _ A Resubmission	/ /	2008/Q4

FOOTNOTE DATA

Schedule Page: 276 Line No.: 8 Column: b

Beginning Balance:	
Rate Case Expenses	624,281
Storm Damages	461,894
SFAS 109 Regulatory Tax Adjustments	2,079,208
Other	(266,806)
	2,898,577

Schedule Page: 276 Line No.: 8 Column: c

Debit Change Account 410.1:	
Storm Damages	828,581
Deferred Gain	1,624,614
IRS Audit Adjustments	22,892
Other	560,089
	3,036,176

Schedule Page: 276 Line No.: 8 Column: d

Credit Change Account 411.1:	
Rate Case Expenses	117,004
IRS Audit Adjustments	446,937
Storm Damages	285,219
Deferred Gain	83,212
Other	406,835
	1,339,207

Schedule Page: 276 Line No.: 8 Column: h

Debit Adjustments:	
SFAS 109 Regulatory Tax Adjustments	201,579

Schedule Page: 276 Line No.: 8 Column: j

Credit Adjustments:	
SFAS 109 Regulatory Tax Adjustments	1,695,271

Schedule Page: 276 Line No.: 8 Column: k

Ending Balance:	
Rate Case Expenses	507,277
Storm Damages	1,005,256
SFAS 109 Regulatory Tax Adjustments	3,572,900
IRS Audit Adjustments	(424,045)
Deferred Gain	1,541,402
Other	(113,552)
	6,089,238

Schedule Page: 276 Line No.: 18 Column: b

Beginning Balance:	
EEI Investment	8,249,551

Schedule Page: 276 Line No.: 18 Column: c

Debit Change Account 410.1:	
EEI Investment	1,588,465

Schedule Page: 276 Line No.: 18 Column: d

Credit Change Account 411.1:

EEI Investment 2,993,399
=========

Schedule Page: 276 Line No.: 18 Column: e

Debit Change Account 410.2:
EEI Investment 669,421
=======

Schedule Page: 276 Line No.: 18 Column: f

Credit Change Account 411.2:
EEI Investment 5,497
=====

Schedule Page: 276 Line No.: 18 Column: k

Ending Balance:
EEI Investment 7,508,541
=========

BLANK

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Utilities Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2008/Q4

OTHER REGULATORY LIABILITIES (Account 254)

1. Report below the particulars (details) called for concerning other regulatory liabilities, including rate order docket number, if applicable.
2. Minor items (5% of the Balance in Account 254 at end of period, or amounts less than $50,000 which ever is less), may be grouped by classes.
3. For Regulatory Liabilities being amortized, show period of amortization.

Line No.	Description and Purpose of Other Regulatory Liabilities	Balance at Begining of Current Quarter/Year	DEBITS		Credits	Balance at End of Current Quarter/Year
			Account Credited	Amount		
	(a)	(b)	(c)	(d)	(e)	(f)
1	SFAS 109 - Income Taxes	29,036,206	190/282	3,086,251		25,949,955
2	MISO Schedule 10 Charges	5,241,563			3,931,171	9,172,734
3	Asset Retirement Obligation	2,170,861	403	13,695	1,744,258	3,901,424
4	Spare Parts	1,272,406	502-514	338,487	525,251	1,459,170
5						
6						
7						
8						
9						
10						
11						
12						
13						
14						
15						
16						
17						
18						
19						
20						
21						
22						
23						
24						
25						
26						
27						
28						
29						
30						
31						
32						
33						
34						
35						
36						
37						
38						
39						
40						
41	TOTAL	37,721,036		3,438,433	6,200,680	40,483,283

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Utilities Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2008/Q4

ELECTRIC OPERATING REVENUES (Account 400)

1. The following instructions generally apply to the annual version of these pages. Do not report quarterly data in columns (c), (e), (f), and (g). Unbilled revenues and MWH related to unbilled revenues need not be reported separately as required in the annual version of these pages.
2. Report below operating revenues for each prescribed account, and manufactured gas revenues in total.
3. Report number of customers, columns (f) and (g), on the basis of meters, in addition to the number of flat rate accounts; except that where separate meter readings are added for billing purposes, one customer should be counted for each group of meters added. The -average number of customers means the average of twelve figures at the close of each month.
4. If increases or decreases from previous period (columns (c),(e), and (g)), are not derived from previously reported figures, explain any inconsistencies in a footnote.

Line No.	Title of Account (a)	Operating Revenues Year to Date Quarterly/Annual (b)	Operating Revenues Previous year (no Quarterly) (c)
1	Sales of Electricity		
2	(440) Residential Sales	462,085,548	430,071,777
3	(442) Commercial and Industrial Sales		
4	Small (or Comm.) (See Instr. 4)	316,402,846	293,558,427
5	Large (or Ind.) (See Instr. 4)	319,256,170	303,223,282
6	(444) Public Street and Highway Lighting	10,014,050	9,371,014
7	(445) Other Sales to Public Authorities	98,034,213	88,231,412
8	(446) Sales to Railroads and Railways		
9	(448) Interdepartmental Sales		
10	TOTAL Sales to Ultimate Consumers	1,205,792,827	1,124,455,912
11	(447) Sales for Resale	188,961,037	140,832,475
12	TOTAL Sales of Electricity	1,394,753,864	1,265,288,387
13	(Less) (449.1) Provision for Rate Refunds		
14	TOTAL Revenues Net of Prov. for Refunds	1,394,753,864	1,265,288,387
15	Other Operating Revenues		
16	(450) Forfeited Discounts		
17	(451) Miscellaneous Service Revenues	1,358,829	1,307,911
18	(453) Sales of Water and Water Power		
19	(454) Rent from Electric Property	2,173,641	2,123,576
20	(455) Interdepartmental Rents		
21	(456) Other Electric Revenues	-3,132,301	-2,945,811
22	(456.1) Revenues from Transmission of Electricity of Others	8,888,020	6,774,836
23	(457.1) Regional Control Service Revenues		
24	(457.2) Miscellaneous Revenues		
25			
26	TOTAL Other Operating Revenues	9,288,189	7,260,512
27	TOTAL Electric Operating Revenues	1,404,042,053	1,272,548,899

Name of Respondent Kentucky Utilities Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2008/Q4

ELECTRIC OPERATING REVENUES (Account 400)

5. Commercial and industrial Sales, Account 442, may be classified according to the basis of classification (Small or Commercial, and Large or Industrial) regularly used by the respondent if such basis of classification is not generally greater than 1000 Kw of demand. (See Account 442 of the Uniform System of Accounts. Explain basis of classification in a footnote.)
6. See pages 108-109, Important Changes During Period, for important new territory added and important rate increase or decreases.
7. For Lines 2,4,5,and 6, see Page 304 for amounts relating to unbilled revenue by accounts.
8. Include unmetered sales. Provide details of such Sales in a footnote.

MEGAWATT HOURS SOLD		AVG.NO. CUSTOMERS PER MONTH		Line No.
Year to Date Quarterly/Annual (d)	Amount Previous year (no Quarterly) (e)	Current Year (no Quarterly) (f)	Previous Year (no Quarterly) (g)	
				1
6,802,830	6,846,775	441,059	439,068	2
				3
4,713,879	4,773,590	83,716	83,047	4
5,995,379	6,273,138	1,918	1,946	5
57,575	56,455	1,477	1,503	6
1,648,938	1,634,506	8,271	7,948	7
				8
				9
19,218,601	19,584,464	536,441	533,512	10
4,865,118	3,640,408	46	51	11
24,083,719	23,224,872	536,487	533,563	12
				13
24,083,719	23,224,872	536,487	533,563	14

Line 12, column (b) includes $ -3,390,864 of unbilled revenues.

Line 12, column (d) includes 50,717 MWH relating to unbilled revenues

BLANK

Schedule Page: 300 Line No.: 5 Column: b

Large category includes Industrial Lighting and Mine Power accounts.

Industrial Sales	$268,939,540
Mine Power	50,316,630
Total Large (or Industrial)	$319,256,170

Schedule Page: 300 Line No.: 5 Column: d

Large category includes Industrial Lighting and Mine Power accounts.

Industrial Sales	5,125,142
Mine Power	870,237
Total Large (or Industrial)	5,995,379 MWH

Schedule Page: 300 Line No.: 7 Column: b

Other category includes Other Sales to Public Authorities and Municipal Pumping accounts.

Other Sales to Public Authorities	$93,273,848
Municipal Pumping	$ 4,760,365
Total Other Sales to Public Authorities	$98,034,213

Schedule Page: 300 Line No.: 7 Column: d

Other category includes Other Sales to Public Authorities and Municipal Pumping accounts.

Other Sales to Public Authorities	1,572,083
Municipal Pumping	76,855
Total Other Sales to Public Authorities	1,648,938 MWH

Schedule Page: 300 Line No.: 21 Column: b

As a result of the Company exiting the MISO, base rate revenues related to the MISO expenses are reclassified from Other Operating Revenues to a Regulatory Liability, as required by the Kentucky Public Service Commission in its May 31, 2006 Order in Case No. 2003-00266.

Schedule Page: 300 Line No.: 21 Column: c

As a result of the Company exiting the MISO, base rate revenues related to the MISO expenses are reclassified from Other Operating Revenues to a Regulatory Liability, as required by the Kentucky Public Service Commission in its May 31, 2006 Order in Case No. 2003-00266.

Schedule Page: 300 Line No.: 1 Column: $

This value contains unbilled revenue of $353,000 and accrued revenue of $(3,743,864). The accrued revenue represents the following:

Energy Revenue Accrual	$ 975,509
FAC Accrual	(8,932,000)
DSM Accrual	(5,052,807)
ECR Accrual	9,488,434
VDT Accrual	39,000
MSR Accrual	(262,000)
Total Accrual	$(3,743,864)

Schedule Page: 300 Line No.: 1 Column: MWH

Unbilled revenue related to 50,717 MWH represents the net change of unbilled MWH from the previous period, and as a result could be positive or negative.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Utilities Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2008/Q4

SALES OF ELECTRICITY BY RATE SCHEDULES

1. Report below for each rate schedule in effect during the year the MWH of electricity sold, revenue, average number of customer, average Kwh per customer, and average revenue per Kwh, excluding date for Sales for Resale which is reported on Pages 310-311.
2. Provide a subheading and total for each prescribed operating revenue account in the sequence followed in "Electric Operating Revenues," Page 300-301. If the sales under any rate schedule are classified in more than one revenue account, List the rate schedule and sales data under each applicable revenue account subheading.
3. Where the same customers are served under more than one rate schedule in the same revenue account classification (such as a general residential schedule and an off peak water heating schedule), the entries in column (d) for the special schedule should denote the duplication in number of reported customers.
4. The average number of customers should be the number of bills rendered during the year divided by the number of billing periods during the year (12 if all billings are made monthly).
5. For any rate schedule having a fuel adjustment clause state in a footnote the estimated additional revenue billed pursuant thereto.
6. Report amount of unbilled revenue as of end of year for each applicable revenue account subheading.

Line No.	Number and Title of Rate schedule (a)	MWh Sold (b)	Revenue (c)	Average Number of Customers (d)	KWh of Sales Per Customer (e)	Revenue Per KWh Sold (f)
1	Account 440					
2	Residential Service - KY	6,299,983	433,954,251	414,322	15,206	0.0689
3	Net Metering Service - KY	90	6,119	4	22,500	0.0680
4	Outdoor Lighting - KY	25,384	3,864,868	41,982	605	0.1523
5	Residential Service - TN	144	2,147	4	36,000	0.0149
6	Full Electric Service - TN	11	256	1	11,000	0.0233
7	Outdoor Lighting - TN	2	144	3	667	0.0720
8	Residential Service - VA	417,968	26,214,878	25,077	16,667	0.0627
9	Outdoor Lighting - VA	3,710	537,278	4,783	776	0.1448
10	Duplicate Customers			-45,117		
11						
12						
13						
14						
15						
16						
17						
18						
19						
20						
21						
22						
23						
24						
25						
26						
27						
28						
29						
30						
31						
32						
33						
34						
35						
36						
37						
38						
39	Unbilled & Other Accruals	55,538	-2,494,393			-0.0449
40	Total for Account 440	6,802,830	462,085,548	441,059	15,424	0.0679
41	TOTAL Billed	19,167,884	1,209,183,691	536,441	35,732	0.0631
42	Total Unbilled Rev.(See Instr. 6)	50,717	-3,390,864	0	0	-0.0669
43	TOTAL	19,218,601	1,205,792,827	536,441	35,826	0.0627

Name of Respondent Kentucky Utilities Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2008/Q4

SALES OF ELECTRICITY BY RATE SCHEDULES

1. Report below for each rate schedule in effect during the year the MWH of electricity sold, revenue, average number of customer, average Kwh per customer, and average revenue per Kwh, excluding date for Sales for Resale which is reported on Pages 310-311.
2. Provide a subheading and total for each prescribed operating revenue account in the sequence followed in "Electric Operating Revenues," Page 300-301. If the sales under any rate schedule are classified in more than one revenue account, List the rate schedule and sales data under each applicable revenue account subheading.
3. Where the same customers are served under more than one rate schedule in the same revenue account classification (such as a general residential schedule and an off peak water heating schedule), the entries in column (d) for the special schedule should denote the duplication in number of reported customers.
4. The average number of customers should be the number of bills rendered during the year divided by the number of billing periods during the year (12 if all billings are made monthly).
5. For any rate schedule having a fuel adjustment clause state in a footnote the estimated additional revenue billed pursuant thereto.
6. Report amount of unbilled revenue as of end of year for each applicable revenue account subheading.

Line No.	Number and Title of Rate schedule (a)	MWh Sold (b)	Revenue (c)	Average Number of Customers (d)	KWh of Sales Per Customer (e)	Revenue Per KWh Sold (f)
1	Account 442					
2	General Service - KY	1,733,317	137,665,599	72,738	23,830	0.0794
3	Net Metering Service - KY	9	927	2	4,500	0.1030
4	All Electric School - KY	15,377	935,233	49	313,816	0.0608
5	Outdoor Lighting - KY	48,687	5,993,231	19,041	2,557	0.1231
6	Small Time-of-Day Service - KY	195,662	10,062,086	52	3,762,731	0.0514
7	Combined Lighting & Power - KY	4,344,599	256,335,163	7,543	575,978	0.0590
8	Large Comm T.O.D. - KY	3,045,974	153,729,076	41	74,292,049	0.0505
9	Mine Power - KY	203,077	12,617,324	42	4,835,167	0.0621
10	Mine Power T.O.D. - KY	351,456	18,955,891	9	39,050,667	0.0539
11	Large Industrial T.O.D. - KY	379,312	22,252,162	1	379,312,000	0.0587
12	Curtailment Service - KY		-5,456,300	2		
13	Redundant Capacity - KY		11,524	2		
14	General Service - VA	84,822	6,335,617	3,531	24,022	0.0747
15	Outdoor Lighting - VA	1,217	186,696	713	1,707	0.1534
16	Large Power Service - VA	324,403	17,779,487	233	1,392,288	0.0548
17	Curtailment Service		-19,200	1		
18	Duplicate Customers			-18,366		
19						
20						
21						
22						
23						
24						
25						
26						
27						
28						
29						
30						
31						
32						
33						
34						
35						
36						
37						
38						
39	Unbilled & Other Accruals	-18,654	-1,725,500			0.0925
40	Total for Account 442	10,709,258	635,659,016	85,634	125,058	0.0594
41	TOTAL Billed	19,167,884	1,209,183,691	536,441	35,732	0.0631
42	Total Unbilled Rev.(See Instr. 6)	50,717	-3,390,864	0	0	-0.0669
43	TOTAL	19,218,601	1,205,792,827	536,441	35,826	0.0627

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Utilities Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2008/Q4

SALES OF ELECTRICITY BY RATE SCHEDULES

1. Report below for each rate schedule in effect during the year the MWH of electricity sold, revenue, average number of customer, average Kwh per customer, and average revenue per Kwh, excluding date for Sales for Resale which is reported on Pages 310-311.
2. Provide a subheading and total for each prescribed operating revenue account in the sequence followed in "Electric Operating Revenues," Page 300-301. If the sales under any rate schedule are classified in more than one revenue account, List the rate schedule and sales data under each applicable revenue account subheading.
3. Where the same customers are served under more than one rate schedule in the same revenue account classification (such as a general residential schedule and an off peak water heating schedule), the entries in column (d) for the special schedule should denote the duplication in number of reported customers.
4. The average number of customers should be the number of bills rendered during the year divided by the number of billing periods during the year (12 if all billings are made monthly).
5. For any rate schedule having a fuel adjustment clause state in a footnote the estimated additional revenue billed pursuant thereto.
6. Report amount of unbilled revenue as of end of year for each applicable revenue account subheading.

Line No.	Number and Title of Rate schedule (a)	MWh Sold (b)	Revenue (c)	Average Number of Customers (d)	KWh of Sales Per Customer (e)	Revenue Per KWh Sold (f)
1	Account 444					
2	General Service - KY	4,002	410,371	901	4,442	0.1025
3	Outdoor Lighting - KY	10	1,342	8	1,250	0.1342
4	Street Lighting - KY	44,774	8,806,806	497	90,089	0.1967
5	Combined Lighting & Power - KY	6,573	423,065	31	212,032	0.0644
6	General Service - VA	57	4,934	7	8,143	0.0866
7	Street Lighting - VA	1,640	266,264	36	45,556	0.1624
8	Duplicate Customers			-3		
9						
10						
11						
12						
13						
14						
15						
16						
17						
18						
19						
20						
21						
22						
23						
24						
25						
26						
27						
28						
29						
30						
31						
32						
33						
34						
35						
36						
37						
38						
39	Unbilled & Other Accruals	519	101,268			0.1951
40	Total for Account 444	57,575	10,014,050	1,477	38,981	0.1739
41	TOTAL Billed	19,167,884	1,209,183,691	536,441	35,732	0.0631
42	Total Unbilled Rev.(See Instr. 6)	50,717	-3,390,864	0	0	-0.0669
43	TOTAL	19,218,601	1,205,792,827	536,441	35,826	0.0627

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Utilities Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2008/Q4

SALES OF ELECTRICITY BY RATE SCHEDULES

1. Report below for each rate schedule in effect during the year the MWH of electricity sold, revenue, average number of customer, average Kwh per customer, and average revenue per Kwh, excluding date for Sales for Resale which is reported on Pages 310-311.
2. Provide a subheading and total for each prescribed operating revenue account in the sequence followed in "Electric Operating Revenues," Page 300-301. If the sales under any rate schedule are classified in more than one revenue account, List the rate schedule and sales data under each applicable revenue account subheading.
3. Where the same customers are served under more than one rate schedule in the same revenue account classification (such as a general residential schedule and an off peak water heating schedule), the entries in column (d) for the special schedule should denote the duplication in number of reported customers.
4. The average number of customers should be the number of bills rendered during the year divided by the number of billing periods during the year (12 if all billings are made monthly).
5. For any rate schedule having a fuel adjustment clause state in a footnote the estimated additional revenue billed pursuant thereto.
6. Report amount of unbilled revenue as of end of year for each applicable revenue account subheading.

Line No.	Number and Title of Rate schedule (a)	MWh Sold (b)	Revenue (c)	Average Number of Customers (d)	KWh of Sales Per Customer (e)	Revenue Per KWh Sold (f)
1	Account 445					
2	Residential Service - KY	2,329	170,712	310	7,513	0.0733
3	Volunteer Fire Department - KY	594	40,400	31	19,161	0.0680
4	General Service - KY	131,292	10,446,661	5,217	25,166	0.0796
5	Net Metering GS - KY	6	421			0.0702
6	All Electric School - KY	115,695	7,097,516	255	453,706	0.0613
7	Outdoor Lighting - KY	6,594	861,440	2,428	2,716	0.1306
8	Combined Lighting & Power - KY	857,875	51,825,724	1,360	630,790	0.0604
9	Large Comm/Ind/T.O.D. - KY	436,932	21,884,864	6	72,822,000	0.0501
10	Redundant Capacity - KY		22,680	2		
11	Residential Service - VA	622	40,059	49	12,694	0.0644
12	General Service - VA	14,930	1,104,357	544	27,445	0.0740
13	School Service - VA	23,965	1,154,206	163	147,025	0.0482
14	Outdoor Lighting - VA	649	99,950	248	2,617	0.1540
15	Large Power Service - VA	43,258	2,505,566	39	1,109,179	0.0579
16	Water Pumping Service - VA	883	51,896	11	80,273	0.0588
17	Duplicate Customer			-2,392		
18						
19						
20						
21						
22						
23						
24						
25						
26						
27						
28						
29						
30						
31						
32						
33						
34						
35						
36						
37						
38						
39	Unbilled & Other Accruals	13,314	727,761			0.0547
40	Total for Account 445	1,648,938	98,034,213	8,271	199,364	0.0595
41	TOTAL Billed	19,167,884	1,209,183,691	536,441	35,732	0.0631
42	Total Unbilled Rev.(See Instr. 6)	50,717	-3,390,864	0	0	-0.0669
43	TOTAL	19,218,601	1,205,792,827	536,441	35,826	0.0627

Schedule Page: 304 Line No.: 2 Column: c
Includes Fuel Adjustment Clause of $21,659,763.

Schedule Page: 304 Line No.: 3 Column: c
Includes Fuel Adjustment Clause of $308.

Schedule Page: 304 Line No.: 4 Column: a
Average number of customers served under this rate schedule 40,596 - included in revenue class subtotal. These are deducted on line 10 to avoid duplication.

Schedule Page: 304 Line No.: 4 Column: c
Includes Fuel Adjustment Clause of $90,941.

Schedule Page: 304 Line No.: 7 Column: a
Average number of customers served under this rate schedule 3 - included in revenue class subtotal. These are deducted on line 10 to avoid duplication.

Schedule Page: 304 Line No.: 9 Column: a
Average number of customers served under this rate schedule 4,518 - included in revenue class subtotal. These are deducted on line 10 to avoid duplication.

Schedule Page: 304 Line No.: 39 Column: b
The MWH relating to unbilled revenues represents the net change of unbilled MWH from the previous period and could be positive or negative.

Schedule Page: 304.1 Line No.: 2 Column: c
Includes Fuel Adjustment Clause of $5,978,246.

Schedule Page: 304.1 Line No.: 3 Column: c
Includes Fuel Adjustment Clause of $27.

Schedule Page: 304.1 Line No.: 4 Column: c
Includes Fuel Adjustment Clause of $53,855.

Schedule Page: 304.1 Line No.: 5 Column: a
Average number of customers served under this rate schedule 17,688 - included in revenue class subtotal. These are deducted on line 18 to avoid duplication.

Schedule Page: 304.1 Line No.: 5 Column: c
Includes Fuel Adjustment Clause of $174,478.

Schedule Page: 304.1 Line No.: 6 Column: c
Includes Fuel Adjustment Clause of $685,172.

Schedule Page: 304.1 Line No.: 7 Column: c
Includes Fuel Adjustment Clause of $15,008,148.

Schedule Page: 304.1 Line No.: 8 Column: c
Includes Fuel Adjustment Clause of $10,448,676.

Schedule Page: 304.1 Line No.: 9 Column: c
Includes Fuel Adjustment Clause of $695,760.

Schedule Page: 304.1 Line No.: 10 Column: c
Includes Fuel Adjustment Clause of $1,234,715.

Schedule Page: 304.1 Line No.: 11 Column: c
Includes Fuel Adjustment Clause of $1,293,069.

Schedule Page: 304.1 Line No.: 12 Column: a
Average number of customers served under this rate schedule 2 - included in revenue class subtotal. These are deducted on line 18 to avoid duplication.

Schedule Page: 304.1 Line No.: 13 Column: a
Average number of customers served under this rate schedule 2 - included in revenue class subtotal. These are deducted on line 18 to avoid duplication.

Schedule Page: 304.1 Line No.: 15 Column: a
Average number of customers served under this rate schedule 673 - included in revenue class subtotal. These are deducted on line 18 to avoid duplication.

Schedule Page: 304.1 Line No.: 17 Column: a
Average number of customers served under this rate schedule 1 - included in revenue class subtotal. These are deducted on line 18 to avoid duplication.

Schedule Page: 304.1 Line No.: 39 Column: b

The MWH relating to unbilled revenues represents the net change of unbilled MWH from the previous period and could be positive or negative.

Schedule Page: 304.2 Line No.: 2 Column: c

Includes Fuel Adjustment Clause of $13,988.

Schedule Page: 304.2 Line No.: 3 Column: a

Average number of customers served under this rate schedule 3 - included in revenue class subtotal. These are deducted on line 8 to avoid duplication.

Schedule Page: 304.2 Line No.: 3 Column: c

Includes Fuel Adjustment Clause of $36.

Schedule Page: 304.2 Line No.: 4 Column: c

Includes Fuel Adjustment Clause of $160,779.

Schedule Page: 304.2 Line No.: 5 Column: c

Includes Fuel Adjustment Clause of $22,225.

Schedule Page: 304.2 Line No.: 39 Column: b

The MWH relating to unbilled revenues represents the net change of unbilled MWH from the previous period and could be positive or negative.

Schedule Page: 304.3 Line No.: 2 Column: c

Includes Fuel Adjustment Clause of $8,030.

Schedule Page: 304.3 Line No.: 3 Column: c

Includes Fuel Adjustment Clause of $2,043.

Schedule Page: 304.3 Line No.: 4 Column: c

Includes Fuel Adjustment Clause of $449,546.

Schedule Page: 304.3 Line No.: 5 Column: c

Includes Fuel Adjustment Clause of $9.

Schedule Page: 304.3 Line No.: 6 Column: c

Includes Fuel Adjustment Clause of $402,229.

Schedule Page: 304.3 Line No.: 7 Column: a

Average number of customers served under this rate schedule 2,165 - included in revenue class subtotal. These are deducted on line 17 to avoid duplication.

Schedule Page: 304.3 Line No.: 7 Column: c

Includes Fuel Adjustment Clause of $23,685.

Schedule Page: 304.3 Line No.: 8 Column: c

Includes Fuel Adjustment Clause of $2,992,482.

Schedule Page: 304.3 Line No.: 9 Column: c

Includes Fuel Adjustment Clause of $1,498,359.

Schedule Page: 304.3 Line No.: 10 Column: a

Average number of customers served under this rate schedule 2 - included in revenue class subtotal. These are deducted on line 17 to avoid duplication.

Schedule Page: 304.3 Line No.: 14 Column: a

Average number of customers served under this rate class 225 - included in revenue class subtotal. These are deducted on line 17 to avoid duplication.

Schedule Page: 304.3 Line No.: 39 Column: b

The MWH relating to unbilled revenues represents the net change of unbilled MWH from the previous period and could be positive or negative.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Utilities Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2008/Q4

SALES FOR RESALE (Account 447)

1. Report all sales for resale (i.e., sales to purchasers other than ultimate consumers) transacted on a settlement basis other than power exchanges during the year. Do not report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges on this schedule. Power exchanges must be reported on the Purchased Power schedule (Page 326-327).
2. Enter the name of the purchaser in column (a). Do note abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the purchaser.
3. In column (b), enter a Statistical Classification Code based on the original contractual terms and conditions of the service as follows:
RQ - for requirements service. Requirements service is service which the supplier plans to provide on an ongoing basis (i.e., the supplier includes projected load for this service in its system resource planning). In addition, the reliability of requirements service must be the same as, or second only to, the supplier's service to its own ultimate consumers.
LF - for tong-term service. "Long-term" means five years or Longer and "firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions (e.g., the supplier must attempt to buy emergency energy from third parties to maintain deliveries of LF service). This category should not be used for Long-term firm service which meets the definition of RQ service. For all transactions identified as LF, provide in a footnote the termination date of the contract defined as the earliest date that either buyer or setter can unilaterally get out of the contract.
IF - for intermediate-term firm service. The same as LF service except that "intermediate-term" means longer than one year but Less than five years.
SF - for short-term firm service. Use this category for all firm services where the duration of each period of commitment for service is one year or less.
LU - for Long-term service from a designated generating unit. "Long-term" means five years or Longer. The availability and reliability of service, aside from transmission constraints, must match the availability and reliability of designated unit.
IU - for intermediate-term service from a designated generating unit. The same as LU service except that "intermediate-term" means Longer than one year but Less than five years.

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Average Monthly CP Demand (f)
1	City of Barbourville	RQ	184	18	18	18
2	City of Bardstown	RQ	185	35	33	31
3	City of Bardwell	RQ	186	2	2	1
4	City of Benham	RQ	187	2	2	2
5	City of Berea	RQ	197	25	25	24
6	City of Corbin	RQ	188	16	16	15
7	City of Falmouth	RQ	189	4	3	3
8	City of Frankfort	RQ	190	124	124	121
9	City of Madisonville-East	RQ	194	8	8	7
10	City of Madisonville-GE Sub.	RQ	192	7	7	6
11	City of Madisonville-Hosp. Sub.	RQ	161	9	9	8
12	City of Madisonville-McCoy Ave.	RQ	162	10	9	8
13	City of Madisonville-S/N	RQ	191	9	8	7
14	City of Madisonville-West	RQ	193	12	12	11
	Subtotal RQ			0	0	0
	Subtotal non-RQ			0	0	0
	Total			**0**	**0**	**0**

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Utilities Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2008/Q4

SALES FOR RESALE (Account 447) (Continued)

OS - for other service. use this category only for those services which cannot be placed in the above-defined categories, such as all non-firm service regardless of the Length of the contract and service from designated units of Less than one year. Describe the nature of the service in a footnote.

AD - for Out-of-period adjustment. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting years. Provide an explanation in a footnote for each adjustment.

4. Group requirements RQ sales together and report them starting at line number one. After listing all RQ sales, enter "Subtotal - RQ" in column (a). The remaining sales may then be listed in any order. Enter "Subtotal-Non-RQ" in column (a) after this Listing. Enter "Total" in column (a) as the Last Line of the schedule. Report subtotals and total for columns (9) through (k)
5. In Column (c), identify the FERC Rate Schedule or Tariff Number. On separate Lines, List all FERC rate schedules or tariffs under which service, as identified in column (b), is provided.
6. For requirements RQ sales and any type of-service involving demand charges imposed on a monthly (or Longer) basis, enter the average monthly billing demand in column (d), the average monthly non-coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP)
demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in columns (e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.
7. Report in column (g) the megawatt hours shown on bills rendered to the purchaser.
8. Report demand charges in column (h), energy charges in column (i), and the total of any other types of charges, including out-of-period adjustments, in column (j). Explain in a footnote all components of the amount shown in column (j). Report in column (k) the total charge shown on bills rendered to the purchaser.
9. The data in column (g) through (k) must be subtotaled based on the RQ/Non-RQ grouping (see instruction 4), and then totaled on the Last -line of the schedule. The "Subtotal - RQ" amount in column (g) must be reported as Requirements Sales For Resale on Page 401, line 23. The "Subtotal - Non-RQ" amount in column (g) must be reported as Non-Requirements Sales For Resale on Page 401,line 24.
10. Footnote entries as required and provide explanations following all required data.

MegaWatt Hours Sold (g)	REVENUE: Demand Charges ($) (h)	Energy Charges ($) (i)	Other Charges ($) (j)	Total ($) (h+i+j) (k)	Line No.
105,168	1,627,597	2,450,414	879,825	4,957,836	1
211,727	3,069,054	4,933,236	1,801,633	9,803,923	2
9,098	153,677	211,993	78,175	443,845	3
7,260	155,947	169,158	57,373	382,478	4
140,959	2,216,732	3,284,337	1,169,355	6,670,424	5
85,908	1,382,641	2,001,656	727,030	4,111,327	6
19,837	313,238	462,198	168,834	944,270	7
752,696	10,992,343	17,537,817	6,315,751	34,845,911	8
43,632	709,272	1,016,626	374,399	2,100,297	9
49,230	657,013	1,147,059	417,207	2,221,279	10
59,309	843,076	1,381,895	509,933	2,734,904	11
50,496	852,079	1,176,557	438,406	2,467,042	12
53,362	771,076	1,243,325	453,687	2,468,088	13
73,335	1,079,637	1,708,692	618,239	3,406,568	14
1,971,405	28,996,637	46,275,993	16,597,458	91,870,088	
2,893,713	0	96,721,445	369,504	97,090,949	
4,865,118	**28,996,637**	**142,997,438**	**16,966,962**	**188,961,037**	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Utilities Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2008/Q4

SALES FOR RESALE (Account 447)

1. Report all sales for resale (i.e., sales to purchasers other than ultimate consumers) transacted on a settlement basis other than power exchanges during the year. Do not report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges on this schedule. Power exchanges must be reported on the Purchased Power schedule (Page 326-327).
2. Enter the name of the purchaser in column (a). Do note abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the purchaser.
3. In column (b), enter a Statistical Classification Code based on the original contractual terms and conditions of the service as follows:
RQ - for requirements service. Requirements service is service which the supplier plans to provide on an ongoing basis (i.e., the supplier includes projected load for this service in its system resource planning). In addition, the reliability of requirements service must be the same as, or second only to, the supplier's service to its own ultimate consumers.
LF - for tong-term service. "Long-term" means five years or Longer and "firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions (e.g., the supplier must attempt to buy emergency energy from third parties to maintain deliveries of LF service). This category should not be used for Long-term firm service which meets the definition of RQ service. For all transactions identified as LF, provide in a footnote the termination date of the contract defined as the earliest date that either buyer or setter can unilaterally get out of the contract.
IF - for intermediate-term firm service. The same as LF service except that "intermediate-term" means longer than one year but Less than five years.
SF - for short-term firm service. Use this category for all firm services where the duration of each period of commitment for service is one year or less.
LU - for Long-term service from a designated generating unit. "Long-term" means five years or Longer. The availability and reliability of service, aside from transmission constraints, must match the availability and reliability of designated unit.
IU - for intermediate-term service from a designated generating unit. The same as LU service except that "intermediate-term" means Longer than one year but Less than five years.

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Average Monthly CP Demand (f)
1	City of Nicholasville-#3	RQ	163	6	6	5
2	City of Nicholasville-#4 & #5	RQ	198	12	12	11
3	City of Nicholasville-#6 & #8	RQ	216	13	12	11
4	City of Nicholasville-#7	RQ	217	6	6	6
5	City of Paris-Bourbon Heights	RQ	83	0	0	0
6	City of Paris-Bourbon Trace 1	RQ	83	0	0	0
7	City of Paris-Bourbon Trace 2	RQ	83	0	0	0
8	City of Paris-Scott/Claysville	RQ	83	8	8	4
9	City of Paris-Vine Street	RQ	83	3	3	3
10	City of Paris-Weaver 1	RQ	83	0	0	0
11	City of Paris-Weaver 2	RQ	83	0	0	0
12	City of Paris-Weaver 3	RQ	83	0	0	0
13	City of Paris-Wilson Drug	RQ	83	0	0	0
14	City of Providence	RQ	195	2	4	3
	Subtotal RQ			0	0	0
	Subtotal non-RQ			0	0	0
	Total			0	0	0

Name of Respondent Kentucky Utilities Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2008/Q4

SALES FOR RESALE (Account 447) (Continued)

OS - for other service. use this category only for those services which cannot be placed in the above-defined categories, such as all non-firm service regardless of the Length of the contract and service from designated units of Less than one year. Describe the nature of the service in a footnote.
AD - for Out-of-period adjustment. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting years. Provide an explanation in a footnote for each adjustment.
4. Group requirements RQ sales together and report them starting at line number one. After listing all RQ sales, enter "Subtotal - RQ" in column (a). The remaining sales may then be listed in any order. Enter "Subtotal-Non-RQ" in column (a) after this Listing. Enter "Total" in column (a) as the Last Line of the schedule. Report subtotals and total for columns (9) through (k)
5. In Column (c), identify the FERC Rate Schedule or Tariff Number. On separate Lines, List all FERC rate schedules or tariffs under which service, as identified in column (b), is provided.
6. For requirements RQ sales and any type of-service involving demand charges imposed on a monthly (or Longer) basis, enter the average monthly billing demand in column (d), the average monthly non-coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP)
demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in columns (e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.
7. Report in column (g) the megawatt hours shown on bills rendered to the purchaser.
8. Report demand charges in column (h), energy charges in column (i), and the total of any other types of charges, including out-of-period adjustments, in column (j). Explain in a footnote all components of the amount shown in column (j). Report in column (k) the total charge shown on bills rendered to the purchaser.
9. The data in column (g) through (k) must be subtotaled based on the RQ/Non-RQ grouping (see instruction 4), and then totaled on the Last -line of the schedule. The "Subtotal - RQ" amount in column (g) must be reported as Requirements Sales For Resale on Page 401, line 23. The "Subtotal - Non-RQ" amount in column (g) must be reported as Non-Requirements Sales For Resale on Page 401,iine 24.
10. Footnote entries as required and provide explanations following all required data.

MegaWatt Hours Sold (g)	REVENUE Demand Charges ($) (h)	Energy Charges ($) (i)	Other Charges ($) (j)	Total ($) (h+i+j) (k)	Line No.
32,246	525,849	751,341	269,982	1,547,172	1
60,840	1,043,133	1,417,581	504,324	2,965,038	2
86,020	1,187,896	2,004,266	715,522	3,907,684	3
34,352	572,371	800,398	291,062	1,663,831	4
1,125		32,258	9,870	42,128	5
408		11,708	3,309	15,017	6
316		9,045	2,596	11,641	7
42,060	55,658	1,205,853	350,607	1,612,118	8
17,655	262,500	506,179	147,661	916,340	9
93		2,680	768	3,448	10
1,001		28,705	8,516	37,221	11
900		25,813	7,638	33,451	12
176		5,054	1,524	6,578	13
19,370	323,367	451,312	165,302	939,981	14
1,971,405	28,996,637	46,275,993	16,597,458	91,870,088	
2,893,713	0	96,721,445	369,504	97,090,949	
4,865,118	**28,996,637**	**142,997,438**	**16,966,962**	**188,961,037**	

Name of Respondent Kentucky Utilities Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2008/Q4

SALES FOR RESALE (Account 447)

1. Report all sales for resale (i.e., sales to purchasers other than ultimate consumers) transacted on a settlement basis other than power exchanges during the year. Do not report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges on this schedule. Power exchanges must be reported on the Purchased Power schedule (Page 326-327).
2. Enter the name of the purchaser in column (a). Do note abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the purchaser.
3. In column (b), enter a Statistical Classification Code based on the original contractual terms and conditions of the service as follows:
RQ - for requirements service. Requirements service is service which the supplier plans to provide on an ongoing basis (i.e., the supplier includes projected load for this service in its system resource planning). In addition, the reliability of requirements service must be the same as, or second only to, the supplier's service to its own ultimate consumers.
LF - for tong-term service. "Long-term" means five years or Longer and "firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions (e.g., the supplier must attempt to buy emergency energy from third parties to maintain deliveries of LF service). This category should not be used for Long-term firm service which meets the definition of RQ service. For all transactions identified as LF, provide in a footnote the termination date of the contract defined as the earliest date that either buyer or setter can unilaterally get out of the contract.
IF - for intermediate-term firm service. The same as LF service except that "intermediate-term" means longer than one year but Less than five years.
SF - for short-term firm service. Use this category for all firm services where the duration of each period of commitment for service is one year or less.
LU - for Long-term service from a designated generating unit. "Long-term" means five years or Longer. The availability and reliability of service, aside from transmission constraints, must match the availability and reliability of designated unit.
IU - for intermediate-term service from a designated generating unit. The same as LU service except that "intermediate-term" means Longer than one year but Less than five years.

Line No.	Name of Company or Public Authority (Footnote Affiliations)	Statistical Classification	FERC Rate Schedule or Tariff Number	Average Monthly Billing Demand (MW)	Actual Demand (MW)	
					Average Monthly NCP Demand	Average Monthly CP Demand
	(a)	(b)	(c)	(d)	(e)	(f)
1	City of Providence-East	RQ	196	2	2	2
2	American Electric Power Service Corp	OS	(2)	NA	NA	NA
3	Associated Electric Coop Inc	OS	(3)	NA	NA	NA
4	Ameren Energy Marketing Company	OS	(3)	NA	NA	NA
5	Ameren Energy, Inc	OS	(3)	NA	NA	NA
6	Cargill Power Markets, LLC	OS	(3)	NA	NA	NA
7	Citigroup Energy Inc.	OS	(3)	NA	NA	NA
8	Cobb Electric Membership Corporation	OS	(3)	NA	NA	NA
9	Constellation Energy Comds. Grp. Inc.	OS	(3)	NA	NA	NA
10	Constellation Energy Comds. Grp. Inc.	AD	(3)	NA	NA	NA
11	DTE Energy Trading Inc.	OS	(3)	NA	NA	NA
12	Duke Energy Carolinas, LLC	OS	(3)	NA	NA	NA
13	East Kentucky Power Cooperative, Inc.	OS	(3)	NA	NA	NA
14	East Kentucky Power Cooperative, Inc.	OS	(6)	NA	NA	NA
	Subtotal RQ			0	0	0
	Subtotal non-RQ			0	0	0
	Total			0	0	0

SALES FOR RESALE (Account 447) (Continued)

OS - for other service. use this category only for those services which cannot be placed in the above-defined categories, such as all non-firm service regardless of the Length of the contract and service from designated units of Less than one year. Describe the nature of the service in a footnote.
AD - for Out-of-period adjustment. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting years. Provide an explanation in a footnote for each adjustment.
4. Group requirements RQ sales together and report them starting at line number one. After listing all RQ sales, enter "Subtotal - RQ" in column (a). The remaining sales may then be listed in any order. Enter "Subtotal-Non-RQ" in column (a) after this Listing. Enter "Total" in column (a) as the Last Line of the schedule. Report subtotals and total for columns (9) through (k)
5. In Column (c), identify the FERC Rate Schedule or Tariff Number. On separate Lines, List all FERC rate schedules or tariffs under which service, as identified in column (b), is provided.
6. For requirements RQ sales and any type of-service involving demand charges imposed on a monthly (or Longer) basis, enter the average monthly billing demand in column (d), the average monthly non-coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP)
demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in columns (e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.
7. Report in column (g) the megawatt hours shown on bills rendered to the purchaser.
8. Report demand charges in column (h), energy charges in column (i), and the total of any other types of charges, including out-of-period adjustments, in column (j). Explain in a footnote all components of the amount shown in column (j). Report in column (k) the total charge shown on bills rendered to the purchaser.
9. The data in column (g) through (k) must be subtotaled based on the RQ/Non-RQ grouping (see instruction 4), and then totaled on the Last -line of the schedule. The "Subtotal - RQ" amount in column (g) must be reported as Requirements Sales For Resale on Page 401, line 23. The "Subtotal - Non-RQ" amount in column (g) must be reported as Non-Requirements Sales For Resale on Page 401,iine 24.
10. Footnote entries as required and provide explanations following all required data.

MegaWatt Hours Sold (g)	REVENUE: Demand Charges ($) (h)	Energy Charges ($) (i)	Other Charges ($) (j)	Total ($) (h+i+j) (k)	Line No.
12,826	202,481	298,837	108,930	610,248	1
1,319		77,741		77,741	2
2,204		133,843		133,843	3
220		13,152		13,152	4
53		2,859		2,859	5
2,837		173,179		173,179	6
686		40,043		40,043	7
3,944		240,659		240,659	8
1,488		93,837		93,837	9
-1			-41	-41	10
79		5,524		5,524	11
1,060		55,278		55,278	12
665		43,097		43,097	13
17		1,179		1,179	14
1,971,405	28,996,637	46,275,993	16,597,458	91,870,088	
2,893,713	0	96,721,445	369,504	97,090,949	
4,865,118	**28,996,637**	**142,997,438**	**16,966,962**	**188,961,037**	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Utilities Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2008/Q4

SALES FOR RESALE (Account 447)

1. Report all sales for resale (i.e., sales to purchasers other than ultimate consumers) transacted on a settlement basis other than power exchanges during the year. Do not report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges on this schedule. Power exchanges must be reported on the Purchased Power schedule (Page 326-327).
2. Enter the name of the purchaser in column (a). Do note abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the purchaser.
3. In column (b), enter a Statistical Classification Code based on the original contractual terms and conditions of the service as follows:
RQ - for requirements service. Requirements service is service which the supplier plans to provide on an ongoing basis (i.e., the supplier includes projected load for this service in its system resource planning). In addition, the reliability of requirements service must be the same as, or second only to, the supplier's service to its own ultimate consumers.
LF - for tong-term service. "Long-term" means five years or Longer and "firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions (e.g., the supplier must attempt to buy emergency energy from third parties to maintain deliveries of LF service). This category should not be used for Long-term firm service which meets the definition of RQ service. For all transactions identified as LF, provide in a footnote the termination date of the contract defined as the earliest date that either buyer or setter can unilaterally get out of the contract.
IF - for intermediate-term firm service. The same as LF service except that "intermediate-term" means longer than one year but Less than five years.
SF - for short-term firm service. Use this category for all firm services where the duration of each period of commitment for service is one year or less.
LU - for Long-term service from a designated generating unit. "Long-term" means five years or Longer. The availability and reliability of service, aside from transmission constraints, must match the availability and reliability of designated unit.
IU - for intermediate-term service from a designated generating unit. The same as LU service except that "intermediate-term" means Longer than one year but Less than five years.

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classifi-cation (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Average Monthly CP Demand (f)
1	Endure Energy	OS	(3)	NA	NA	NA
2	Fortis Energy Marketing & Trading GP	OS	(3)	NA	NA	NA
3	Illinois Municipal Electric Agency	OS	(5)	NA	NA	NA
4	Indiana Municipal Power Agency	OS	(5)	NA	NA	NA
5	Integrys Energy Services	OS	(3)	NA	NA	NA
6	Kansas City Power & Light	OS	(3)	NA	NA	NA
7	Louisville Gas & Electric Company	SF	(1)	NA	NA	NA
8	MF Global Inc.	OS		NA	NA	NA
9	Merrill Lynch Commodities, Inc.	OS	(3)	NA	NA	NA
10	Midwest Independent Transmission System	OS	(3)	NA	NA	NA
11	Midwest ISO Contingency Reserve Sharing	OS	(7)	NA	NA	NA
12	Owensboro Municipal Utilities	OS	(9)	NA	NA	NA
13	PJM Interconnection Assosication	OS	(3)	NA	NA	NA
14	Progress Energy Ventures Inc.	OS	(3)	NA	NA	NA
	Subtotal RQ			0	0	0
	Subtotal non-RQ			0	0	0
	Total			0	0	0

Name of Respondent Kentucky Utilities Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2008/Q4

SALES FOR RESALE (Account 447) (Continued)

OS - for other service. use this category only for those services which cannot be placed in the above-defined categories, such as all non-firm service regardless of the Length of the contract and service from designated units of Less than one year. Describe the nature of the service in a footnote.
AD - for Out-of-period adjustment. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting years. Provide an explanation in a footnote for each adjustment.
4. Group requirements RQ sales together and report them starting at line number one. After listing all RQ sales, enter "Subtotal - RQ" in column (a). The remaining sales may then be listed in any order. Enter "Subtotal-Non-RQ" in column (a) after this Listing. Enter "Total" in column (a) as the Last Line of the schedule. Report subtotals and total for columns (9) through (k)
5. In Column (c), identify the FERC Rate Schedule or Tariff Number. On separate Lines, List all FERC rate schedules or tariffs under which service, as identified in column (b), is provided.
6. For requirements RQ sales and any type of-service involving demand charges imposed on a monthly (or Longer) basis, enter the average monthly billing demand in column (d), the average monthly non-coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP)
demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in columns (e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.
7. Report in column (g) the megawatt hours shown on bills rendered to the purchaser.
8. Report demand charges in column (h), energy charges in column (i), and the total of any other types of charges, including out-of-period adjustments, in column (j). Explain in a footnote all components of the amount shown in column (j). Report in column (k) the total charge shown on bills rendered to the purchaser.
9. The data in column (g) through (k) must be subtotaled based on the RQ/Non-RQ grouping (see instruction 4), and then totaled on the Last -line of the schedule. The "Subtotal - RQ" amount in column (g) must be reported as Requirements Sales For Resale on Page 401, line 23. The "Subtotal - Non-RQ" amount in column (g) must be reported as Non-Requirements Sales For Resale on Page 401,iine 24.
10. Footnote entries as required and provide explanations following all required data.

MegaWatt Hours Sold (g)	REVENUE Demand Charges ($) (h)	Energy Charges ($) (i)	Other Charges ($) (j)	Total ($) (h+i+j) (k)	Line No.
1,727		84,798		84,798	1
617		37,322		37,322	2
2,544		264,614		264,614	3
1,986		202,925		202,925	4
178		13,105		13,105	5
10		417		417	6
2,579,175		79,520,474		79,520,474	7
			369,545	369,545	8
536		34,048		34,048	9
76,351		3,850,703		3,850,703	10
469		65,658		65,658	11
47,427		2,496,167		2,496,167	12
121,205		6,685,615		6,685,615	13
10,125		526,606		526,606	14
1,971,405	28,996,637	46,275,993	16,597,458	91,870,088	
2,893,713	0	96,721,445	369,504	97,090,949	
4,865,118	**28,996,637**	**142,997,438**	**16,966,962**	**188,961,037**	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Utilities Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2008/Q4

SALES FOR RESALE (Account 447)

1. Report all sales for resale (i.e., sales to purchasers other than ultimate consumers) transacted on a settlement basis other than power exchanges during the year. Do not report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges on this schedule. Power exchanges must be reported on the Purchased Power schedule (Page 326-327).
2. Enter the name of the purchaser in column (a). Do note abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the purchaser.
3. In column (b), enter a Statistical Classification Code based on the original contractual terms and conditions of the service as follows:
RQ - for requirements service. Requirements service is service which the supplier plans to provide on an ongoing basis (i.e., the supplier includes projected load for this service in its system resource planning). In addition, the reliability of requirements service must be the same as, or second only to, the supplier's service to its own ultimate consumers.
LF - for tong-term service. "Long-term" means five years or Longer and "firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions (e.g., the supplier must attempt to buy emergency energy from third parties to maintain deliveries of LF service). This category should not be used for Long-term firm service which meets the definition of RQ service. For all transactions identified as LF, provide in a footnote the termination date of the contract defined as the earliest date that either buyer or setter can unilaterally get out of the contract.
IF - for intermediate-term firm service. The same as LF service except that "intermediate-term" means longer than one year but Less than five years.
SF - for short-term firm service. Use this category for all firm services where the duration of each period of commitment for service is one year or less.
LU - for Long-term service from a designated generating unit. "Long-term" means five years or Longer. The availability and reliability of service, aside from transmission constraints, must match the availability and reliability of designated unit.
IU - for intermediate-term service from a designated generating unit. The same as LU service except that "intermediate-term" means Longer than one year but Less than five years.

Line No.	Name of Company or Public Authority (Footnote Affiliations)	Statistical Classification	FERC Rate Schedule or Tariff Number	Average Monthly Billing Demand (MW)	Actual Demand (MW)	
					Average Monthly NCP Demand	Average Monthly CP Demand
	(a)	(b)	(c)	(d)	(e)	(f)
1	Rainbow Energy Marketing Corp	OS	(3)	NA	NA	NA
2	Southern Company Services, Inc	OS	(3)	NA	NA	NA
3	Tenaska Power Services Co	OS	(3)	NA	NA	NA
4	Tennessee Valley Authority	OS	(3)	NA	NA	NA
5	The Energy Authority	OS	(2)	NA	NA	NA
6	Transalta Energy Marketing (U.S.) Inc.	OS	(3)	NA	NA	NA
7	Westar Energy, Inc.	OS	(3)	NA	NA	NA
8						
9						
10						
11						
12						
13						
14						
	Subtotal RQ			0	0	0
	Subtotal non-RQ			0	0	0
	Total			0	0	0

OS - for other service. use this category only for those services which cannot be placed in the above-defined categories, such as all non-firm service regardless of the Length of the contract and service from designated units of Less than one year. Describe the nature of the service in a footnote.
AD - for Out-of-period adjustment. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting years. Provide an explanation in a footnote for each adjustment.
4. Group requirements RQ sales together and report them starting at line number one. After listing all RQ sales, enter "Subtotal - RQ" in column (a). The remaining sales may then be listed in any order. Enter "Subtotal-Non-RQ" in column (a) after this Listing. Enter "Total" in column (a) as the Last Line of the schedule. Report subtotals and total for columns (9) through (k)
5. In Column (c), identify the FERC Rate Schedule or Tariff Number. On separate Lines, List all FERC rate schedules or tariffs under which service, as identified in column (b), is provided.
6. For requirements RQ sales and any type of-service involving demand charges imposed on a monthly (or Longer) basis, enter the average monthly billing demand in column (d), the average monthly non-coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP)
demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in columns (e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.
7. Report in column (g) the megawatt hours shown on bills rendered to the purchaser.
8. Report demand charges in column (h), energy charges in column (i), and the total of any other types of charges, including out-of-period adjustments, in column (j). Explain in a footnote all components of the amount shown in column (j). Report in column (k) the total charge shown on bills rendered to the purchaser.
9. The data in column (g) through (k) must be subtotaled based on the RQ/Non-RQ grouping (see instruction 4), and then totaled on the Last -line of the schedule. The "Subtotal - RQ" amount in column (g) must be reported as Requirements Sales For Resale on Page 401, line 23. The "Subtotal - Non-RQ" amount in column (g) must be reported as Non-Requirements Sales For Resale on Page 401,iine 24.
10. Footnote entries as required and provide explanations following all required data.

MegaWatt Hours Sold (g)	REVENUE Demand Charges ($) (h)	Energy Charges ($) (i)	Other Charges ($) (j)	Total ($) (h+i+j) (k)	Line No.
27		1,174		1,174	1
8,935		470,725		470,725	2
1,937		118,610		118,610	3
15,846		903,650		903,650	4
9,290		517,421		517,421	5
39		1,651		1,651	6
718		45,371		45,371	7
					8
					9
					10
					11
					12
					13
					14
1,971,405	28,996,637	46,275,993	16,597,458	91,870,088	
2,893,713	0	96,721,445	369,504	97,090,949	
4,865,118	**28,996,637**	**142,997,438**	**16,966,962**	**188,961,037**	

Schedule Page: 310 Line No.: 1 Column: j
All amounts in column J (other charges) for RQ's relate to wholesale municipal fuel adjustment clause.

Schedule Page: 310 Line No.: 2 Column: j
All amounts in column J (other charges) for RQ's relate to wholesale municipal fuel adjustment clause.

Schedule Page: 310 Line No.: 3 Column: j
All amounts in column J (other charges) for RQ's relate to wholesale municipal fuel adjustment clause.

Schedule Page: 310 Line No.: 4 Column: j
All amounts in column J (other charges) for RQ's relate to wholesale municipal fuel adjustment clause.

Schedule Page: 310 Line No.: 5 Column: j
All amounts in column J (other charges) for RQ's relate to wholesale municipal fuel adjustment clause.

Schedule Page: 310 Line No.: 6 Column: j
All amounts in column J (other charges) for RQ's relate to wholesale municipal fuel adjustment clause.

Schedule Page: 310 Line No.: 7 Column: j
All amounts in column J (other charges) for RQ's relate to wholesale municipal fuel adjustment clause.

Schedule Page: 310 Line No.: 8 Column: j
All amounts in column J (other charges) for RQ's relate to wholesale municipal fuel adjustment clause.

Schedule Page: 310 Line No.: 9 Column: j
All amounts in column J (other charges) for RQ's relate to wholesale municipal fuel adjustment clause.

Schedule Page: 310 Line No.: 10 Column: j
All amounts in column J (other charges) for RQ's relate to wholesale municipal fuel adjustment clause.

Schedule Page: 310 Line No.: 11 Column: j
All amounts in column J (other charges) for RQ's relate to wholesale municipal fuel adjustment clause.

Schedule Page: 310 Line No.: 12 Column: j
All amounts in column J (other charges) for RQ's relate to wholesale municipal fuel adjustment clause.

Schedule Page: 310 Line No.: 13 Column: j
All amounts in column J (other charges) for RQ's relate to wholesale municipal fuel adjustment clause.

Schedule Page: 310 Line No.: 14 Column: j
All amounts in column J (other charges) for RQ's relate to wholesale municipal fuel adjustment clause.

Schedule Page: 310.1 Line No.: 1 Column: j
All amounts in column J (other charges) for RQ's relate to wholesale municipal fuel adjustment clause.

Schedule Page: 310.1 Line No.: 2 Column: j
All amounts in column J (other charges) for RQ's relate to wholesale municipal fuel adjustment clause.

Schedule Page: 310.1 Line No.: 3 Column: j
All amounts in column J (other charges) for RQ's relate to wholesale municipal fuel adjustment clause.

Schedule Page: 310.1 Line No.: 4 Column: j
All amounts in column J (other charges) for RQ's relate to wholesale municipal fuel adjustment clause.

Schedule Page: 310.1 Line No.: 5 Column: j
All amounts in column J (other charges) for RQ's relate to wholesale municipal fuel adjustment clause.

Schedule Page: 310.1 Line No.: 6 Column: j
All amounts in column J (other charges) for RQ's relate to wholesale municipal fuel adjustment clause.

Schedule Page: 310.1 Line No.: 7 Column: j
All amounts in column J (other charges) for RQ's relate to wholesale municipal fuel adjustment clause.

Schedule Page: 310.1 Line No.: 8 Column: j
All amounts in column J (other charges) for RQ's relate to wholesale municipal fuel adjustment clause.

Schedule Page: 310.1 Line No.: 9 Column: j
All amounts in column J (other charges) for RQ's relate to wholesale municipal fuel adjustment clause.

Schedule Page: 310.1 Line No.: 10 Column: j
All amounts in column J (other charges) for RQ's relate to wholesale municipal fuel adjustment clause.

Schedule Page: 310.1 Line No.: 11 Column: j
All amounts in column J (other charges) for RQ's relate to wholesale municipal fuel adjustment clause.

Schedule Page: 310.1 Line No.: 12 Column: j
All amounts in column J (other charges) for RQ's relate to wholesale municipal fuel adjustment clause.

Schedule Page: 310.1 Line No.: 13 Column: j
All amounts in column J (other charges) for RQ's relate to wholesale municipal fuel adjustment clause.
Schedule Page: 310.1 Line No.: 14 Column: j
All amounts in column J (other charges) for RQ's relate to wholesale municipal fuel adjustment clause.
Schedule Page: 310.2 Line No.: 1 Column: j
All amounts in column J (other charges) for RQ's relate to wholesale municipal fuel adjustment clause.
Schedule Page: 310.2 Line No.: 2 Column: b
Market Based Sale
Schedule Page: 310.2 Line No.: 2 Column: c
(2) FERC Electric Tariff, Original Volume No. 2
Schedule Page: 310.2 Line No.: 3 Column: b
Market Based Sale
Schedule Page: 310.2 Line No.: 3 Column: c
(3) FERC Electric Tariff, Original Volume No. 3
Schedule Page: 310.2 Line No.: 4 Column: b
Market Based Sale
Schedule Page: 310.2 Line No.: 4 Column: c
(3) FERC Electric Tariff, Original Volume No. 3
Schedule Page: 310.2 Line No.: 5 Column: b
Market Based Sale
Schedule Page: 310.2 Line No.: 5 Column: c
(3) FERC Electric Tariff, Original Volume No. 3
Schedule Page: 310.2 Line No.: 6 Column: b
Market Based Sale
Schedule Page: 310.2 Line No.: 6 Column: c
(3) FERC Electric Tariff, Original Volume No. 3
Schedule Page: 310.2 Line No.: 7 Column: b
Market Based Sale
Schedule Page: 310.2 Line No.: 7 Column: c
(3) FERC Electric Tariff, Original Volume No. 3
Schedule Page: 310.2 Line No.: 8 Column: b
Market Based Sale
Schedule Page: 310.2 Line No.: 8 Column: c
(3) FERC Electric Tariff, Original Volume No. 3
Schedule Page: 310.2 Line No.: 9 Column: b
Market Based Sale
Schedule Page: 310.2 Line No.: 9 Column: c
(3) FERC Electric Tariff, Original Volume No. 3
Schedule Page: 310.2 Line No.: 10 Column: b
December 2007 correction of both MWH and dollars made in 2008.
Schedule Page: 310.2 Line No.: 10 Column: c
(3) FERC Electric Tariff, Original Volume No. 3
Schedule Page: 310.2 Line No.: 10 Column: g
December 2007 correction of both MWH and dollars made in 2008.
Schedule Page: 310.2 Line No.: 10 Column: j
December 2007 correction of both MWH and dollars made in 2008.
Schedule Page: 310.2 Line No.: 11 Column: b
Market Based Sale
Schedule Page: 310.2 Line No.: 11 Column: c
(3) FERC Electric Tariff, Original Volume No. 3
Schedule Page: 310.2 Line No.: 12 Column: b
Market Based Sale

Schedule Page: 310.2 Line No.: 12 Column: c
(3) FERC Electric Tariff, Original Volume No. 3

Schedule Page: 310.2 Line No.: 13 Column: b
Market Based Sale

Schedule Page: 310.2 Line No.: 13 Column: c
(3) FERC Electric Tariff, Original Volume No. 3

Schedule Page: 310.2 Line No.: 14 Column: b
Energy Imbalance

Schedule Page: 310.2 Line No.: 14 Column: c
(6) E.ON US OATT FERC Electric Tariff Vol. 1 Fourth Rev and East Kentucky Power Coop. OATT FERC Electric Tariff Vol. 1 Second Rev.

Schedule Page: 310.3 Line No.: 1 Column: b
Market Based Sale

Schedule Page: 310.3 Line No.: 1 Column: c
(3) FERC Electric Tariff, Original Volume No. 3

Schedule Page: 310.3 Line No.: 2 Column: b
Market Based Sale

Schedule Page: 310.3 Line No.: 2 Column: c
(3) FERC Electric Tariff, Original Volume No. 3

Schedule Page: 310.3 Line No.: 3 Column: b
Cost Based Sale

Schedule Page: 310.3 Line No.: 3 Column: c
(5) FERC Electric Tariff, Original Volume No. 5

Schedule Page: 310.3 Line No.: 4 Column: b
Cost Based Sale

Schedule Page: 310.3 Line No.: 4 Column: c
(5) FERC Electric Tariff, Original Volume No. 5

Schedule Page: 310.3 Line No.: 5 Column: b
Market Based Sale

Schedule Page: 310.3 Line No.: 5 Column: c
(3) FERC Electric Tariff, Original Volume No. 3

Schedule Page: 310.3 Line No.: 6 Column: b
Market Based Sale

Schedule Page: 310.3 Line No.: 6 Column: c
(3) FERC Electric Tariff, Original Volume No. 3

Schedule Page: 310.3 Line No.: 7 Column: a
Louisville Gas and Electric Company and Kentucky Utilities Company are both owned by E.ON U.S. LLC.

Schedule Page: 310.3 Line No.: 7 Column: c
(1) FERC Rate Schedule No. 1. The Power Supply System Agreement, FERC Docket No. ER98-111-000

Schedule Page: 310.3 Line No.: 8 Column: b
Financial Swap

Schedule Page: 310.3 Line No.: 8 Column: j
Financial Swap

Schedule Page: 310.3 Line No.: 9 Column: b
Market Based Sale

Schedule Page: 310.3 Line No.: 9 Column: c
(3) FERC Electric Tariff, Original Volume No. 3

Schedule Page: 310.3 Line No.: 10 Column: b
Market Based Sale

Schedule Page: 310.3 Line No.: 10 Column: c
(3) FERC Electric Tariff, Original Volume No. 3

Schedule Page: 310.3 Line No.: 11 Column: a

The Midwest ISO Contingency Reserve Sharing Group (MISO CRSG) is not a signatory to the CRSG contract. The MISO CRSG is the group administrator and serves as the clearing house for the CRSG billing. The CRSG group is comprised of the following members: Alliant East, Alliant West, Ameren Illinois, Ameren Missouri, Ames Municipal, Basin Electric Power Cooperative, Big Rivers, City of Springfield, City of Columbia Missouri, Consumers, Dairyland Power Cooperative, DTE Energy, Duke Energy, Duke Energy Indiana, Duke Energy Kentucky, Duke Energy Ohio, East Kentucky Power Coop, E.ON US, First Energy, GEN-SYS Energy, Great River Energy, Hastings Municipal, Heartland Consumers Power Dist, Hoosier Energy REC, Hutchinson Utilities Commission, Indianapolis Power & Light Co, Lincoln Electric System, Madison Gas & Electric, Manitoba Hydro, Michigan Electric Coordinated System, MidAmerican Energy Company, Minnesota Municipal Power Agency, Minnesota Power Inc, Minnkota Power Cooperative, Missouri River Energy Services, Montana-Dakota Utilities Inc, Municipal Energy Agency of Nebraska, Muscatine Power and Water, Nebraska Public Power District, Northern Indiana Public Service Co, Northwestern Energy, NSP Companies, Omaha Public Power District, Otter Tail Power Company, Rochester Public Utilities, So Minnesota Municipal Power Agency, Southern Illinois Power Coop, Upper Peninsula Power Co, Vectren, Western Area Power Administration, Willmar Municipal Utilities, Wisconsin Energy Corporation, Wisconsin Public Power Inc, and Wisconsin Public Service Corp.

Schedule Page: 310.3 Line No.: 11 Column: b

Emergency Power

Schedule Page: 310.3 Line No.: 11 Column: c

(7) MISO FERC Electric Tariff Rate Schedule No. 9

Schedule Page: 310.3 Line No.: 11 Column: g

MWH for the Midwest ISO (MISO) members are excluded to avoid double-counting; MWH for the MISO members are reported with the MISO as part of the energy markets invoice using the FERC Order 668 MWH netting requirement.

Schedule Page: 310.3 Line No.: 11 Column: i

Energy dollars for amount representing LMP are reported with the MISO as part of the energy markets invoice using the FERC Order 668 MWH netting requirement.

Schedule Page: 310.3 Line No.: 12 Column: b

Backup Power

Schedule Page: 310.3 Line No.: 12 Column: c

(9) FERC Electric Tariff FPC 74

Schedule Page: 310.3 Line No.: 13 Column: b

Market Based Sale

Schedule Page: 310.3 Line No.: 13 Column: c

(3) FERC Electric Tariff, Original Volume No. 3

Schedule Page: 310.3 Line No.: 14 Column: b

Market Based Sale

Schedule Page: 310.3 Line No.: 14 Column: c

(3) FERC Electric Tariff, Original Volume No. 3

Schedule Page: 310.4 Line No.: 1 Column: b

Market Based Sale

Schedule Page: 310.4 Line No.: 1 Column: c

(3) FERC Electric Tariff, Original Volume No. 3

Schedule Page: 310.4 Line No.: 2 Column: b

Market Based Sale

Schedule Page: 310.4 Line No.: 2 Column: c

(3) FERC Electric Tariff, Original Volume No. 3

Schedule Page: 310.4 Line No.: 3 Column: b

Market Based Sale

Schedule Page: 310.4 Line No.: 3 Column: c

(3) FERC Electric Tariff, Original Volume No. 3

Schedule Page: 310.4 Line No.: 4 Column: b

Market Based Sale

Schedule Page: 310.4 Line No.: 4 Column: c

(3) FERC Electric Tariff, Original Volume No. 3

Schedule Page: 310.4 Line No.: 5 Column: b

BLANK

Market Based Sale

Schedule Page: 310.4 Line No.: 5 Column: c

(2) FERC Electric Tariff, Original Volume No. 2

Schedule Page: 310.4 Line No.: 6 Column: b

Market Based Sale

Schedule Page: 310.4 Line No.: 6 Column: c

(3) FERC Electric Tariff, Original Volume No. 3

Schedule Page: 310.4 Line No.: 7 Column: b

Market Based Sale

Schedule Page: 310.4 Line No.: 7 Column: c

(3) FERC Electric Tariff, Original Volume No. 3

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Utilities Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2008/Q4

ELECTRIC OPERATION AND MAINTENANCE EXPENSES

If the amount for previous year is not derived from previously reported figures, explain in footnote.

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)
1	1. POWER PRODUCTION EXPENSES		
2	A. Steam Power Generation		
3	Operation		
4	(500) Operation Supervision and Engineering	4,096,569	3,884,997
5	(501) Fuel	468,318,498	402,527,315
6	(502) Steam Expenses	12,298,437	9,983,115
7	(503) Steam from Other Sources		
8	(Less) (504) Steam Transferred-Cr.		
9	(505) Electric Expenses	5,592,653	5,596,263
10	(506) Miscellaneous Steam Power Expenses	10,595,994	7,282,652
11	(507) Rents		
12	(509) Allowances	619,818	2,614,525
13	TOTAL Operation (Enter Total of Lines 4 thru 12)	501,521,969	431,888,867
14	Maintenance		
15	(510) Maintenance Supervision and Engineering	6,147,126	4,952,714
16	(511) Maintenance of Structures	5,408,039	5,036,929
17	(512) Maintenance of Boiler Plant	25,209,896	27,400,811
18	(513) Maintenance of Electric Plant	9,741,859	10,556,105
19	(514) Maintenance of Miscellaneous Steam Plant	1,059,004	1,065,291
20	TOTAL Maintenance (Enter Total of Lines 15 thru 19)	47,565,924	49,011,850
21	TOTAL Power Production Expenses-Steam Power (Entr Tot lines 13 & 20)	549,087,893	480,900,717
22	B. Nuclear Power Generation		
23	Operation		
24	(517) Operation Supervision and Engineering		
25	(518) Fuel		
26	(519) Coolants and Water		
27	(520) Steam Expenses		
28	(521) Steam from Other Sources		
29	(Less) (522) Steam Transferred-Cr.		
30	(523) Electric Expenses		
31	(524) Miscellaneous Nuclear Power Expenses		
32	(525) Rents		
33	TOTAL Operation (Enter Total of lines 24 thru 32)		
34	Maintenance		
35	(528) Maintenance Supervision and Engineering		
36	(529) Maintenance of Structures		
37	(530) Maintenance of Reactor Plant Equipment		
38	(531) Maintenance of Electric Plant		
39	(532) Maintenance of Miscellaneous Nuclear Plant		
40	TOTAL Maintenance (Enter Total of lines 35 thru 39)		
41	TOTAL Power Production Expenses-Nuc. Power (Entr tot lines 33 & 40)		
42	C. Hydraulic Power Generation		
43	Operation		
44	(535) Operation Supervision and Engineering	7,332	8,950
45	(536) Water for Power		
46	(537) Hydraulic Expenses		
47	(538) Electric Expenses		
48	(539) Miscellaneous Hydraulic Power Generation Expenses	42,056	30,470
49	(540) Rents		
50	TOTAL Operation (Enter Total of Lines 44 thru 49)	49,388	39,420
51	C. Hydraulic Power Generation (Continued)		
52	Maintenance		
53	(541) Mainentance Supervision and Engineering	104,880	107,573
54	(542) Maintenance of Structures	148,534	144,686
55	(543) Maintenance of Reservoirs, Dams, and Waterways		
56	(544) Maintenance of Electric Plant	76,469	197,756
57	(545) Maintenance of Miscellaneous Hydraulic Plant	5,629	5,459
58	TOTAL Maintenance (Enter Total of lines 53 thru 57)	335,512	455,474
59	TOTAL Power Production Expenses-Hydraulic Power (tot of lines 50 & 58)	384,900	494,894

ELECTRIC OPERATION AND MAINTENANCE EXPENSES (Continued)

If the amount for previous year is not derived from previously reported figures, explain in footnote.

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)
60	D. Other Power Generation		
61	Operation		
62	(546) Operation Supervision and Engineering	177,861	74,616
63	(547) Fuel	44,080,973	57,591,370
64	(548) Generation Expenses	2,352,366	713,415
65	(549) Miscellaneous Other Power Generation Expenses	137,843	144,288
66	(550) Rents		
67	TOTAL Operation (Enter Total of lines 62 thru 66)	46,749,043	58,523,689
68	Maintenance		
69	(551) Maintenance Supervision and Engineering	106,233	42,895
70	(552) Maintenance of Structures	157,283	150,424
71	(553) Maintenance of Generating and Electric Plant	2,318,502	2,975,965
72	(554) Maintenance of Miscellaneous Other Power Generation Plant	517,893	252,060
73	TOTAL Maintenance (Enter Total of lines 69 thru 72)	3,099,911	3,421,344
74	TOTAL Power Production Expenses-Other Power (Enter Tot of 67 & 73)	49,848,954	61,945,033
75	E. Other Power Supply Expenses		
76	(555) Purchased Power	221,176,768	168,443,606
77	(556) System Control and Load Dispatching	1,593,466	1,552,192
78	(557) Other Expenses	980,360	1,666,475
79	TOTAL Other Power Supply Exp (Enter Total of lines 76 thru 78)	223,750,594	171,662,273
80	TOTAL Power Production Expenses (Total of lines 21, 41, 59, 74 & 79)	823,072,341	715,002,917
81	2. TRANSMISSION EXPENSES		
82	Operation		
83	(560) Operation Supervision and Engineering	1,987,071	916,089
84	(561) Load Dispatching	1,028,651	957,968
85	(561.1) Load Dispatch-Reliability		
86	(561.2) Load Dispatch-Monitor and Operate Transmission System		
87	(561.3) Load Dispatch-Transmission Service and Scheduling		
88	(561.4) Scheduling, System Control and Dispatch Services	19,268	259
89	(561.5) Reliability, Planning and Standards Development		
90	(561.6) Transmission Service Studies	47,889	18,891
91	(561.7) Generation Interconnection Studies		
92	(561.8) Reliability, Planning and Standards Development Services	1,386	18
93	(562) Station Expenses	400,774	458,794
94	(563) Overhead Lines Expenses	424,984	400,237
95	(564) Underground Lines Expenses		
96	(565) Transmission of Electricity by Others	6,315,049	4,484,694
97	(566) Miscellaneous Transmission Expenses	4,842,910	6,293,929
98	(567) Rents	99,500	56,986
99	TOTAL Operation (Enter Total of lines 83 thru 98)	15,167,482	13,587,865
100	Maintenance		
101	(568) Maintenance Supervision and Engineering		
102	(569) Maintenance of Structures		
103	(569.1) Maintenance of Computer Hardware		
104	(569.2) Maintenance of Computer Software		
105	(569.3) Maintenance of Communication Equipment		
106	(569.4) Maintenance of Miscellaneous Regional Transmission Plant		
107	(570) Maintenance of Station Equipment	1,212,830	1,169,930
108	(571) Maintenance of Overhead Lines	3,143,960	3,515,529
109	(572) Maintenance of Underground Lines		
110	(573) Maintenance of Miscellaneous Transmission Plant	375,802	309,324
111	TOTAL Maintenance (Total of lines 101 thru 110)	4,732,592	4,994,783
112	TOTAL Transmission Expenses (Total of lines 99 and 111)	19,900,074	18,582,648

Name of Respondent Kentucky Utilities Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2008/Q4

ELECTRIC OPERATION AND MAINTENANCE EXPENSES (Continued)

If the amount for previous year is not derived from previously reported figures, explain in footnote.

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)
113	3. REGIONAL MARKET EXPENSES		
114	Operation		
115	(575.1) Operation Supervision		
116	(575.2) Day-Ahead and Real-Time Market Facilitation		
117	(575.3) Transmission Rights Market Facilitation		
118	(575.4) Capacity Market Facilitation		
119	(575.5) Ancillary Services Market Facilitation		
120	(575.6) Market Monitoring and Compliance		
121	(575.7) Market Facilitation, Monitoring and Compliance Services	38,293	5,792
122	(575.8) Rents		
123	Total Operation (Lines 115 thru 122)	38,293	5,792
124	Maintenance		
125	(576.1) Maintenance of Structures and Improvements		
126	(576.2) Maintenance of Computer Hardware		
127	(576.3) Maintenance of Computer Software		
128	(576.4) Maintenance of Communication Equipment		
129	(576.5) Maintenance of Miscellaneous Market Operation Plant		
130	Total Maintenance (Lines 125 thru 129)		
131	TOTAL Regional Transmission and Market Op Expns (Total 123 and 130)	38,293	5,792
132	4. DISTRIBUTION EXPENSES		
133	Operation		
134	(580) Operation Supervision and Engineering	1,437,058	1,337,127
135	(581) Load Dispatching	603,830	667,273
136	(582) Station Expenses	1,229,962	1,103,556
137	(583) Overhead Line Expenses	4,122,244	2,806,778
138	(584) Underground Line Expenses	72,556	85,185
139	(585) Street Lighting and Signal System Expenses	10,104	6,500
140	(586) Meter Expenses	6,521,240	6,202,616
141	(587) Customer Installations Expenses	80,541	81,768
142	(588) Miscellaneous Expenses	4,687,096	4,557,460
143	(589) Rents	12,842	13,002
144	TOTAL Operation (Enter Total of lines 134 thru 143)	18,616,391	16,697,729
145	Maintenance		
146	(590) Maintenance Supervision and Engineering	7,745	7,927
147	(591) Maintenance of Structures	685	
148	(592) Maintenance of Station Equipment	959,759	813,560
149	(593) Maintenance of Overhead Lines	22,896,107	19,293,285
150	(594) Maintenance of Underground Lines	630,133	621,863
151	(595) Maintenance of Line Transformers	79,117	112,521
152	(596) Maintenance of Street Lighting and Signal Systems	60,839	81,269
153	(597) Maintenance of Meters		
154	(598) Maintenance of Miscellaneous Distribution Plant	-5,118	11,846
155	TOTAL Maintenance (Total of lines 146 thru 154)	24,629,267	20,942,271
156	TOTAL Distribution Expenses (Total of lines 144 and 155)	43,245,658	37,640,000
157	5. CUSTOMER ACCOUNTS EXPENSES		
158	Operation		
159	(901) Supervision	1,940,125	1,991,238
160	(902) Meter Reading Expenses	3,761,113	4,292,201
161	(903) Customer Records and Collection Expenses	12,515,610	11,681,015
162	(904) Uncollectible Accounts	3,919,708	2,323,942
163	(905) Miscellaneous Customer Accounts Expenses	334,960	173,641
164	TOTAL Customer Accounts Expenses (Total of lines 159 thru 163)	22,471,516	20,462,037

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Utilities Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2008/Q4

ELECTRIC OPERATION AND MAINTENANCE EXPENSES (Continued)

If the amount for previous year is not derived from previously reported figures, explain in footnote.

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)
165	6. CUSTOMER SERVICE AND INFORMATIONAL EXPENSES		
166	Operation		
167	(907) Supervision	252,037	234,620
168	(908) Customer Assistance Expenses	2,726,413	4,748,069
169	(909) Informational and Instructional Expenses	68,864	536,623
170	(910) Miscellaneous Customer Service and Informational Expenses	1,870,819	747,973
171	TOTAL Customer Service and Information Expenses (Total 167 thru 170)	4,918,133	6,267,285
172	7. SALES EXPENSES		
173	Operation		
174	(911) Supervision		
175	(912) Demonstrating and Selling Expenses		
176	(913) Advertising Expenses	58,162	48,890
177	(916) Miscellaneous Sales Expenses		
178	TOTAL Sales Expenses (Enter Total of lines 174 thru 177)	58,162	48,890
179	8. ADMINISTRATIVE AND GENERAL EXPENSES		
180	Operation		
181	(920) Administrative and General Salaries	16,142,090	15,682,009
182	(921) Office Supplies and Expenses	6,798,911	7,271,153
183	(Less) (922) Administrative Expenses Transferred-Credit	1,992,872	1,316,492
184	(923) Outside Services Employed	12,763,789	8,985,949
185	(924) Property Insurance	2,832,972	3,394,768
186	(925) Injuries and Damages	1,226,235	1,178,211
187	(926) Employee Pensions and Benefits	24,119,043	22,618,725
188	(927) Franchise Requirements	3,196	3,206
189	(928) Regulatory Commission Expenses	1,192,613	930,738
190	(929) (Less) Duplicate Charges-Cr.	3,196	3,206
191	(930.1) General Advertising Expenses	585,277	445,124
192	(930.2) Miscellaneous General Expenses	1,738,084	1,545,718
193	(931) Rents	1,741,354	1,565,377
194	TOTAL Operation (Enter Total of lines 181 thru 193)	67,147,496	62,301,280
195	Maintenance		
196	(935) Maintenance of General Plant	8,415,586	6,416,472
197	TOTAL Administrative & General Expenses (Total of lines 194 and 196)	75,563,082	68,717,752
198	TOTAL Elec Op and Maint Expns (Total 80,112,131,156,164,171,178,197)	989,267,259	866,727,321

BLANK

Schedule Page: 320 Line No.: 141 Column: b

The credit is due to meter tampering charges billed to customers to offset the cost of meter maintenance. The cost is recorded in several accounts.

Schedule Page: 320 Line No.: 141 Column: c

The credit is due to meter tampering charges billed to customers to offset the cost of meter maintenance. The cost is recorded in several accounts.

Schedule Page: 320 Line No.: 154 Column: b

The credit balance is due to an out-of-period adjustment for uncollectible Sundry accounts receivable.

PURCHASED POWER (Account 555)
(Including power exchanges)

1. Report all power purchases made during the year. Also report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges.
2. Enter the name of the seller or other party in an exchange transaction in column (a). Do not abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the seller.
3. In column (b), enter a Statistical Classification Code based on the original contractual terms and conditions of the service as follows:

RQ - for requirements service. Requirements service is service which the supplier plans to provide on an ongoing basis (i.e., the supplier includes projects load for this service in its system resource planning). In addition, the reliability of requirement service must be the same as, or second only to, the supplier's service to its own ultimate consumers.

LF - for long-term firm service. "Long-term" means five years or longer and "firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions (e.g., the supplier must attempt to buy emergency energy from third parties to maintain deliveries of LF service). This category should not be used for long-term firm service firm service which meets the definition of RQ service. For all transaction identified as LF, provide in a footnote the termination date of the contract defined as the earliest date that either buyer or seller can unilaterally get out of the contract.

IF - for intermediate-term firm service. The same as LF service expect that "intermediate-term" means longer than one year but less than five years.

SF - for short-term service. Use this category for all firm services, where the duration of each period of commitment for service is one year or less.

LU - for long-term service from a designated generating unit. "Long-term" means five years or longer. The availability and reliability of service, aside from transmission constraints, must match the availability and reliability of the designated unit.

IU - for intermediate-term service from a designated generating unit. The same as LU service expect that "intermediate-term" means longer than one year but less than five years.

EX - For exchanges of electricity. Use this category for transactions involving a balancing of debits and credits for energy, capacity, etc. and any settlements for imbalanced exchanges.

OS - for other service. Use this category only for those services which cannot be placed in the above-defined categories, such as all non-firm service regardless of the Length of the contract and service from designated units of Less than one year. Describe the nature of the service in a footnote for each adjustment.

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)
1	Ameren Energy Marketing Company	OS	(1)	NA	NA	NA
2	Ameren UE	OS	(1)	NA	NA	NA
3	American Electric Power Service Corp	OS	(1)	NA	NA	NA
4	Associated Electric Coop Inc	OS	(1)	NA	NA	NA
5	Big Rivers Electric Corp.	OS	(1)	NA	NA	NA
6	Bluegrass Generation Company LLC	OS	(5)	NA	NA	NA
7	Cargill Power Markets, LLC	OS	(1)	NA	NA	NA
8	Citigroup Energy Inc.	OS	(1)	NA	NA	NA
9	Cobb Electric Membership Corporation	OS	(1)	NA	NA	NA
10	Constellation Energy Comds. Grp Inc.	OS	(1)	NA	NA	NA
11	DTE Energy Trading Inc	OS	(1)	NA	NA	NA
12	Dynegy Power Marketing, Inc	OS	(1)	165	168	
13	Duke Energy Carolinas, LLC	OS	(1)	NA	NA	NA
14	East Kentucky Power Coop. Inc.	OS	(1)	NA	NA	NA
	Total					

PURCHASED POWER(Account 555) (Continued)
(Including power exchanges)

AD - for out-of-period adjustment. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting years. Provide an explanation in a footnote for each adjustment.

4. In column (c), identify the FERC Rate Schedule Number or Tariff, or, for non-FERC jurisdictional sellers, include an appropriate designation for the contract. On separate lines, list all FERC rate schedules, tariffs or contract designations under which service, as identified in column (b), is provided.
5. For requirements RQ purchases and any type of service involving demand charges imposed on a monnthly (or longer) basis, enter the monthly average billing demand in column (d), the average monthly non-coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP) demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in columns (e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.
6. Report in column (g) the megawatthours shown on bills rendered to the respondent. Report in columns (h) and (i) the megawatthours of power exchanges received and delivered, used as the basis for settlement. Do not report net exchange.
7. Report demand charges in column (j), energy charges in column (k), and the total of any other types of charges, including out-of-period adjustments, in column (l). Explain in a footnote all components of the amount shown in column (l). Report in column (m) the total charge shown on bills received as settlement by the respondent. For power exchanges, report in column (m) the settlement amount for the net receipt of energy. If more energy was delivered than received, enter a negative amount. If the settlement amount (l) include credits or charges other than incremental generation expenses, or (2) excludes certain credits or charges covered by the agreement, provide an explanatory footnote.
8. The data in column (g) through (m) must be totalled on the last line of the schedule. The total amount in column (g) must be reported as Purchases on Page 401, line 10. The total amount in column (h) must be reported as Exchange Received on Page 401, line 12. The total amount in column (i) must be reported as Exchange Delivered on Page 401, line 13.
9. Footnote entries as required and provide explanations following all required data.

MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	
3,266				267,672		267,672	1
10,217				813,554		813,554	2
10,203				748,186		748,186	3
7,041				503,172		503,172	4
31				2,867		2,867	5
139				5,483		5,483	6
15,610				1,169,517		1,169,517	7
100				8,500		8,500	8
3,155				238,820		238,820	9
7,944				625,392		625,392	10
583				44,985		44,985	11
43,043			1,386,000	4,916,424		6,302,424	12
1,225				87,200		87,200	13
85				12,914		12,914	14
7,095,014	34,513	28,951	23,221,165	198,150,909	-195,306	221,176,768	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Utilities Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2008/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

1. Report all power purchases made during the year. Also report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges.
2. Enter the name of the seller or other party in an exchange transaction in column (a). Do not abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the seller.
3. In column (b), enter a Statistical Classification Code based on the original contractual terms and conditions of the service as follows:

RQ - for requirements service. Requirements service is service which the supplier plans to provide on an ongoing basis (i.e., the supplier includes projects load for this service in its system resource planning). In addition, the reliability of requirement service must be the same as, or second only to, the supplier's service to its own ultimate consumers.

LF - for long-term firm service. "Long-term" means five years or longer and "firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions (e.g., the supplier must attempt to buy emergency energy from third parties to maintain deliveries of LF service). This category should not be used for long-term firm service firm service which meets the definition of RQ service. For all transaction identified as LF, provide in a footnote the termination date of the contract defined as the earliest date that either buyer or seller can unilaterally get out of the contract.

IF - for intermediate-term firm service. The same as LF service expect that "intermediate-term" means longer than one year but less than five years.

SF - for short-term service. Use this category for all firm services, where the duration of each period of commitment for service is one year or less.

LU - for long-term service from a designated generating unit. "Long-term" means five years or longer. The availability and reliability of service, aside from transmission constraints, must match the availability and reliability of the designated unit.

IU - for intermediate-term service from a designated generating unit. The same as LU service expect that "intermediate-term" means longer than one year but less than five years.

EX - For exchanges of electricity. Use this category for transactions involving a balancing of debits and credits for energy, capacity, etc. and any settlements for imbalanced exchanges.

OS - for other service. Use this category only for those services which cannot be placed in the above-defined categories, such as all non-firm service regardless of the Length of the contract and service from designated units of Less than one year. Describe the nature of the service in a footnote for each adjustment.

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Average Monthly CP Demand (f)
1	East Kentucky Power Coop. Inc.	OS	(3)	NA	NA	NA
2	Fortis Energy Marketing & Trading GP	OS	(1)	NA	NA	NA
3	Indiana Municipal Power Agency	OS	(7)	NA	NA	NA
4	Integrys Energy Services	OS	(1)	NA	NA	NA
5	Louisville Gas & Electric Co.	SF	(2)	NA	NA	NA
6	Merrill Lynch Commodities, Inc.	OS	(1)	NA	NA	NA
7	Midwest Independent Transmission Oper.	OS	(1)	NA	NA	NA
8	Midwest ISO Contingency Reserv Sharing	OS	(4)	NA	NA	NA
9	Midwest ISO Contingency Reserv Sharing	AD	(4)	NA	NA	NA
10	Ohio Valley Electric Corporation	OS	(6)	NA	NA	NA
11	Ohio Valley Electric Corporation	AD	(6)	NA	NA	NA
12	Owensboro Municipal Utilities	RQ	(7)	163	260	
13	Owensboro Municipal Utilities	AD	(7)	NA	NA	NA
14	PJM Interconnection Association	OS	(1)	NA	NA	NA
	Total					

PURCHASED POWER(Account 555) (Continued)
(Including power exchanges)

AD - for out-of-period adjustment. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting years. Provide an explanation in a footnote for each adjustment.

4. In column (c), identify the FERC Rate Schedule Number or Tariff, or, for non-FERC jurisdictional sellers, include an appropriate designation for the contract. On separate lines, list all FERC rate schedules, tariffs or contract designations under which service, as identified in column (b), is provided.
5. For requirements RQ purchases and any type of service involving demand charges imposed on a monnthly (or longer) basis, enter the monthly average billing demand in column (d), the average monthly non-coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP) demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in columns (e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.
6. Report in column (g) the megawatthours shown on bills rendered to the respondent. Report in columns (h) and (i) the megawatthours of power exchanges received and delivered, used as the basis for settlement. Do not report net exchange.
7. Report demand charges in column (j), energy charges in column (k), and the total of any other types of charges, including out-of-period adjustments, in column (l). Explain in a footnote all components of the amount shown in column (l). Report in column (m) the total charge shown on bills received as settlement by the respondent. For power exchanges, report in column (m) the settlement amount for the net receipt of energy. If more energy was delivered than received, enter a negative amount. If the settlement amount (l) include credits or charges other than incremental generation expenses, or (2) excludes certain credits or charges covered by the agreement, provide an explanatory footnote.
8. The data in column (g) through (m) must be totalled on the last line of the schedule. The total amount in column (g) must be reported as Purchases on Page 401, line 10. The total amount in column (h) must be reported as Exchange Received on Page 401, line 12. The total amount in column (i) must be reported as Exchange Delivered on Page 401, line 13.
9. Footnote entries as required and provide explanations following all required data.

MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	
2,433				103,732		103,732	1
4,852				409,750		409,750	2
423				18,612		18,612	3
100				10,000		10,000	4
5,056,906				109,345,605		109,345,605	5
2,504				216,334		216,334	6
213,733				16,476,623		16,476,623	7
196				84,893		84,893	8
					-12	-12	9
375,805			6,583,170	8,407,658		14,990,828	10
					-122,828	-122,828	11
1,170,202			15,251,995	41,085,207		56,337,202	12
					-72,466	-72,466	13
151,817				11,451,395		11,451,395	14
7,095,014	34,513	28,951	23,221,165	198,150,909	-195,306	221,176,768	

Name of Respondent Kentucky Utilities Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2008/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

1. Report all power purchases made during the year. Also report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges.
2. Enter the name of the seller or other party in an exchange transaction in column (a). Do not abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the seller.
3. In column (b), enter a Statistical Classification Code based on the original contractual terms and conditions of the service as follows:

RQ - for requirements service. Requirements service is service which the supplier plans to provide on an ongoing basis (i.e., the supplier includes projects load for this service in its system resource planning). In addition, the reliability of requirement service must be the same as, or second only to, the supplier's service to its own ultimate consumers.

LF - for long-term firm service. "Long-term" means five years or longer and "firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions (e.g., the supplier must attempt to buy emergency energy from third parties to maintain deliveries of LF service). This category should not be used for long-term firm service firm service which meets the definition of RQ service. For all transaction identified as LF, provide in a footnote the termination date of the contract defined as the earliest date that either buyer or seller can unilaterally get out of the contract.

IF - for intermediate-term firm service. The same as LF service expect that "intermediate-term" means longer than one year but less than five years.

SF - for short-term service. Use this category for all firm services, where the duration of each period of commitment for service is one year or less.

LU - for long-term service from a designated generating unit. "Long-term" means five years or longer. The availability and reliability of service, aside from transmission constraints, must match the availability and reliability of the designated unit.

IU - for intermediate-term service from a designated generating unit. The same as LU service expect that "intermediate-term" means longer than one year but less than five years.

EX - For exchanges of electricity. Use this category for transactions involving a balancing of debits and credits for energy, capacity, etc. and any settlements for imbalanced exchanges.

OS - for other service. Use this category only for those services which cannot be placed in the above-defined categories, such as all non-firm service regardless of the Length of the contract and service from designated units of Less than one year. Describe the nature of the service in a footnote for each adjustment.

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)
1	Southern Company Services, Inc.	OS	(1)	NA	NA	NA
2	Tenaska Power Services Co	OS	(1)	NA	NA	NA
3	The Energy Authority	OS	(1)	NA	NA	NA
4	Tennessee Valley Authority	OS	(1)	NA	NA	NA
5	Westar Energy, Inc.	OS	(1)	NA	NA	NA
6	Inadvertant Interchange			NA	NA	NA
7						
8						
9						
10						
11						
12						
13						
14						
	Total					

PURCHASED POWER(Account 555) (Continued)
(Including power exchanges)

AD - for out-of-period adjustment. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting years. Provide an explanation in a footnote for each adjustment.

4. In column (c), identify the FERC Rate Schedule Number or Tariff, or, for non-FERC jurisdictional sellers, include an appropriate designation for the contract. On separate lines, list all FERC rate schedules, tariffs or contract designations under which service, as identified in column (b), is provided.
5. For requirements RQ purchases and any type of service involving demand charges imposed on a monnthly (or longer) basis, enter the monthly average billing demand in column (d), the average monthly non-coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP) demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in columns (e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.
6. Report in column (g) the megawatthours shown on bills rendered to the respondent. Report in columns (h) and (i) the megawatthours of power exchanges received and delivered, used as the basis for settlement. Do not report net exchange.
7. Report demand charges in column (j), energy charges in column (k), and the total of any other types of charges, including out-of-period adjustments, in column (l). Explain in a footnote all components of the amount shown in column (l). Report in column (m) the total charge shown on bills received as settlement by the respondent. For power exchanges, report in column (m) the settlement amount for the net receipt of energy. If more energy was delivered than received, enter a negative amount. If the settlement amount (l) include credits or charges other than incremental generation expenses, or (2) excludes certain credits or charges covered by the agreement, provide an explanatory footnote.
8. The data in column (g) through (m) must be totalled on the last line of the schedule. The total amount in column (g) must be reported as Purchases on Page 401, line 10. The total amount in column (h) must be reported as Exchange Received on Page 401, line 12. The total amount in column (i) must be reported as Exchange Delivered on Page 401, line 13.
9. Footnote entries as required and provide explanations following all required data.

MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	
1,296				95,000		95,000	1
451				20,408		20,408	2
8,515				768,728		768,728	3
451				28,004		28,004	4
2,688				184,274		184,274	5
	34,513	28,951					6
							7
							8
							9
							10
							11
							12
							13
							14
7,095,014	34,513	28,951	23,221,165	198,150,909	-195,306	221,176,768	

Schedule Page: 326 Line No.: 1 Column: b
Market Based Purchase
Schedule Page: 326 Line No.: 1 Column: c
(1) FERC-approved tariff and/or rate schedule as on file with the Commission.
Schedule Page: 326 Line No.: 2 Column: b
Market Based Purchase
Schedule Page: 326 Line No.: 2 Column: c
(1) FERC-approved tariff and/or rate schedule as on file with the Commission.
Schedule Page: 326 Line No.: 3 Column: b
Market Based Purchase
Schedule Page: 326 Line No.: 3 Column: c
(1) FERC-approved tariff and/or rate schedule as on file with the Commission.
Schedule Page: 326 Line No.: 4 Column: b
Market Based Purchase
Schedule Page: 326 Line No.: 4 Column: c
(1) FERC-approved tariff and/or rate schedule as on file with the Commission.
Schedule Page: 326 Line No.: 5 Column: b
Energy Imbalance
Schedule Page: 326 Line No.: 5 Column: c
(1) FERC-approved tariff and/or rate schedule as on file with the Commission.
Schedule Page: 326 Line No.: 6 Column: b
Energy Imbalance
Schedule Page: 326 Line No.: 6 Column: c
(5) FERC Electric Tariff, Original Volume No. 2, Service Agreement No. 255
Schedule Page: 326 Line No.: 7 Column: b
Market Based Purchase
Schedule Page: 326 Line No.: 7 Column: c
(1) FERC-approved tariff and/or rate schedule as on file with the Commission.
Schedule Page: 326 Line No.: 8 Column: b
Market Based Purchase
Schedule Page: 326 Line No.: 8 Column: c
(1) FERC-approved tariff and/or rate schedule as on file with the Commission.
Schedule Page: 326 Line No.: 9 Column: b
Market Based Purchase
Schedule Page: 326 Line No.: 9 Column: c
(1) FERC-approved tariff and/or rate schedule as on file with the Commission.
Schedule Page: 326 Line No.: 10 Column: b
Market Based Purchase
Schedule Page: 326 Line No.: 10 Column: c
(1) FERC-approved tariff and/or rate schedule as on file with the Commission.
Schedule Page: 326 Line No.: 11 Column: b
Market Based Purchase
Schedule Page: 326 Line No.: 11 Column: c
(1) FERC-approved tariff and/or rate schedule as on file with the Commission.
Schedule Page: 326 Line No.: 12 Column: b
Purchase Power
Schedule Page: 326 Line No.: 12 Column: c
(1) FERC-approved tariff and/or rate schedule as on file with the Commission.
Schedule Page: 326 Line No.: 12 Column: f
The supplier's system monthly peak is not available to Kentucky Utilities Company.
Schedule Page: 326 Line No.: 13 Column: b
Market Based Purchase

Schedule Page: 326 Line No.: 13 Column: c
(1) FERC-approved tariff and/or rate schedule as on file with the Commission.

Schedule Page: 326 Line No.: 14 Column: b
Market Based Purchase

Schedule Page: 326 Line No.: 14 Column: c
(1) FERC-approved tariff and/or rate schedule as on file with the Commission.

Schedule Page: 326.1 Line No.: 1 Column: b
Energy Imbalance

Schedule Page: 326.1 Line No.: 1 Column: c
(3) E.ON U.S. OATT FERC Electric Tariff Vol. 1 Fourth Rev and East Kentucky Power Coop. OATT FERC Electric Tariff Vol. 1 Second Rev.

Schedule Page: 326.1 Line No.: 2 Column: b
Market Based Purchase

Schedule Page: 326.1 Line No.: 2 Column: c
(1) FERC-approved tariff and/or rate schedule as on file with the Commission.

Schedule Page: 326.1 Line No.: 3 Column: b
Market Based Purchase

Schedule Page: 326.1 Line No.: 3 Column: c
(7) Interchange Agreement FERC Schedule No. 31

Schedule Page: 326.1 Line No.: 4 Column: b
Market Based Purchase

Schedule Page: 326.1 Line No.: 4 Column: c
(1) FERC-approved tariff and/or rate schedule as on file with the Commission.

Schedule Page: 326.1 Line No.: 5 Column: a
Kentucky Utilities Company and Louisville Gas and Electric Company are both owned by E.ON U.S. LLC.

Schedule Page: 326.1 Line No.: 5 Column: c
(2) FERC Rate Schedule No. 1. The Power Supply System Agreement, FERC Docket No. ER98-111-000

Schedule Page: 326.1 Line No.: 6 Column: b
Market Based Purchase

Schedule Page: 326.1 Line No.: 6 Column: c
(1) FERC-approved tariff and/or rate schedule as on file with the Commission.

Schedule Page: 326.1 Line No.: 7 Column: b
Market Based Purchase

Schedule Page: 326.1 Line No.: 7 Column: c
(1) FERC-approved tariff and/or rate schedule as on file with the Commission.

Schedule Page: 326.1 Line No.: 8 Column: a
The Midwest ISO Contingency Reserve Sharing Group (MISO CRSG) is not a signatory to the CRSG contract. The MISO CRSG is the group administrator and serves as the clearing house for the CRSG billing. The CRSG group is comprised of the following members: Alliant East, Alliant West, Ameren Illinois, Ameren Missouri, Ames Municipal, Basin Electric Power Cooperative, Big Rivers, City of Springfield, City of Columbia Missouri, Consumers, Dairyland Power Cooperative, DTE Energy, Duke Energy, Duke Energy Indiana, Duke Energy Kentucky, Duke Energy Ohio, East Kentucky Power Coop, E.ON US, First Energy, GEN-SYS Energy, Great River Energy, Hastings Municipal, Heartland Consumers Power Dist, Hoosier Energy REC, Hutchinson Utilities Commission, Indianapolis Power & Light Co, Lincoln Electric System, Madison Gas & Electric, Manitoba Hydro, Michigan Electric Coordinated System, MidAmerican Energy Company, Minnesota Municipal Power Agency, Minnesota Power Inc, Minnkota Power Cooperative, Missouri River Energy Services, Montana-Dakota Utilities Inc, Municipal Energy Agency of Nebraska, Muscatine Power and Water, Nebraska Public Power District, Northern Indiana Public Service Co, Northwestern Energy, NSP Companies, Omaha Public Power District, Otter Tail Power Company, Rochester Public Utilities, So Minnesota Municipal Power Agency, Southern Illinois Power Coop, Upper Peninsula Power Co, Vectren, Western Area Power Administration, Willmar Municipal Utilities, Wisconsin Energy Corporation, Wisconsin Public Power Inc and Wisconsin Public Service Corp.

Schedule Page: 326.1 Line No.: 8 Column: b
Emergency Power

Schedule Page: 326.1 Line No.: 8 Column: c

(4) MISO FERC Electric Tariff Rate Schedule No. 9

Schedule Page: 326.1 Line No.: 8 Column: g

MWH for the Midwest ISO (MISO) members are excluded to avoid double-counting; MWH for the MISO members are reported with the MISO as part of the energy markets invoice using the FERC Order 668 MWH netting requirement.

Schedule Page: 326.1 Line No.: 8 Column: k

Energy dollars for amount representing LMP are reported with the Midwest ISO (MISO) as part of the energy markets invoice using the FERC Order 668 MWH netting requirement.

Schedule Page: 326.1 Line No.: 9 Column: a

The Midwest ISO Contingency Reserve Sharing Group (MISO CRSG) is not a signatory to the CRSG contract. The MISO CRSG is the group administrator and serves as the clearing house for the CRSG billing. The CRSG group is comprised of the following members: Alliant East, Alliant West, Ameren Illinois, Ameren Missouri, Ames Municipal, Basin Electric Power Cooperative, Big Rivers, City of Springfield, City of Columbia Missouri, Consumers, Dairyland Power Cooperative, DTE Energy, Duke Energy, Duke Energy Indiana, Duke Energy Kentucky, Duke Energy Ohio, East Kentucky Power Coop, E.ON US, First Energy, GEN-SYS Energy, Great River Energy, Hastings Municipal, Heartland Consumers Power Dist, Hoosier Energy REC, Hutchinson Utilities Commission, Indianapolis Power & Light Co, Lincoln Electric System, Madison Gas & Electric, Manitoba Hydro, Michigan Electric Coordinated System, MidAmerican Energy Company, Minnesota Municipal Power Agency, Minnesota Power Inc, Minnkota Power Cooperative, Missouri River Energy Services, Montana-Dakota Utilities Inc, Municipal Energy Agency of Nebraska, Muscatine Power and Water, Nebraska Public Power District, Northern Indiana Public Service Co, Northwestern Energy, NSP Companies, Omaha Public Power District, Otter Tail Power Company, Rochester Public Utilities, So Minnesota Municipal Power Agency, Southern Illinois Power Coop, Upper Peninsula Power Co, Vectren, Western Area Power Administration, Willmar Municipal Utilities, Wisconsin Energy Corporation, Wisconsin Public Power Inc and Wisconsin Public Service Corp.

Schedule Page: 326.1 Line No.: 9 Column: b

True-up of December 2007 accrual estimate.

Schedule Page: 326.1 Line No.: 9 Column: c

(4) MISO FERC Electric Tariff Rate Schedule No. 9

Schedule Page: 326.1 Line No.: 9 Column: l

True-up of December 2007 accrual estimate.

Schedule Page: 326.1 Line No.: 10 Column: a

The Company owns 2.5% of the common stock of Ohio Valley Electric Corporation (OVEC). Purchase of surplus power pursuant to Article 4 of the Amended and Restated Inter-company Power Agreement among OVEC and Sponsoring Companies dated March 13, 2006.

Schedule Page: 326.1 Line No.: 10 Column: b

Surplus Power

Schedule Page: 326.1 Line No.: 10 Column: c

(6) Purchase of surplus power pursuant to Article 4 of the Amended and Restated Inter-company Power Agreement among OVEC and Sponsoring Companies dated March 13, 2006.

Schedule Page: 326.1 Line No.: 11 Column: a

The Company owns 2.5% of the common stock of OVEC. Purchase of surplus power pursuant to Article 4 of the Amended and Restated Inter-company Power Agreement among OVEC and Sponsoring Companies dated March 13, 2006.

Schedule Page: 326.1 Line No.: 11 Column: b

December 2007 true-up of accrual estimate for both energy and demand charges booked in 2008. Previous years' FERC Form 1 reports included these out-of-period adjustments in the current year because they were considered standard monthly adjustments. On a go-forward basis, these out-of-period adjustments will be shown separately.

Schedule Page: 326.1 Line No.: 11 Column: c

(6) Purchase of surplus power pursuant to Article 4 of the Amended and Restated Inter-company Power Agreement among OVEC and Sponsoring Companies dated March 13, 2006.

Schedule Page: 326.1 Line No.: 11 Column: l

December 2007 true up of accrual estimate for both energy ($19,188) and demand charges (-$142,016) made in 2008.

Schedule Page: 326.1 Line No.: 12 Column: c

(7) FERC Electric Tariff FPC 74

Schedule Page: 326.1 Line No.: 12 Column: f

The supplier's system monthly peak is not available to Kentucky Utilities Company.

Schedule Page: 326.1 Line No.: 13 Column: b

December 2007 true-up of accrual estimate for both energy and demand charges booked in 2008. Previous years' FERC Form 1 reports included these out-of-period adjustments in the current year because they were considered standard monthly adjustments. On a go-forward basis, these out-of-period adjustments will be shown separately.

Schedule Page: 326.1 Line No.: 13 Column: c

(7) FERC Electric Tariff FPC 74

Schedule Page: 326.1 Line No.: 13 Column: l

December 2007 true up of accrual estimate for both energy (-$22,292) and demand charges (-$50,174) made in 2008.

Schedule Page: 326.1 Line No.: 14 Column: b

Market Based Purchase

Schedule Page: 326.1 Line No.: 14 Column: c

(1) FERC-approved tariff and/or rate schedule as on file with the Commission.

Schedule Page: 326.2 Line No.: 1 Column: b

Market Based Purchase

Schedule Page: 326.2 Line No.: 1 Column: c

(1) FERC-approved tariff and/or rate schedule as on file with the Commission.

Schedule Page: 326.2 Line No.: 2 Column: b

Market Based Purchase

Schedule Page: 326.2 Line No.: 2 Column: c

(1) FERC-approved tariff and/or rate schedule as on file with the Commission.

Schedule Page: 326.2 Line No.: 3 Column: b

Market Based Purchase

Schedule Page: 326.2 Line No.: 3 Column: c

(1) FERC-approved tariff and/or rate schedule as on file with the Commission.

Schedule Page: 326.2 Line No.: 4 Column: b

Market Based Purchase

Schedule Page: 326.2 Line No.: 4 Column: c

(1) FERC-approved tariff and/or rate schedule as on file with the Commission.

Schedule Page: 326.2 Line No.: 5 Column: b

Market Based Purchase

Schedule Page: 326.2 Line No.: 5 Column: c

(1) FERC-approved tariff and/or rate schedule as on file with the Commission.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Utilities Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2008/Q4

TRANSMISSION OF ELECTRICITY FOR OTHERS (Account 456.1)
(Including transactions referred to as 'wheeling')

1. Report all transmission of electricity, i.e., wheeling, provided for other electric utilities, cooperatives, other public authorities, qualifying facilities, non-traditional utility suppliers and ultimate customers for the quarter.
2. Use a separate line of data for each distinct type of transmission service involving the entities listed in column (a), (b) and (c).
3. Report in column (a) the company or public authority that paid for the transmission service. Report in column (b) the company or public authority that the energy was received from and in column (c) the company or public authority that the energy was delivered to. Provide the full name of each company or public authority. Do not abbreviate or truncate name or use acronyms. Explain in a footnote any ownership interest in or affiliation the respondent has with the entities listed in columns (a), (b) or (c)
4. In column (d) enter a Statistical Classification code based on the original contractual terms and conditions of the service as follows: FNO - Firm Network Service for Others, FNS - Firm Network Transmission Service for Self, LFP - "Long-Term Firm Point to Point Transmission Service, OLF - Other Long-Term Firm Transmission Service, SFP - Short-Term Firm Point to Point Transmission Reservation, NF - non-firm transmission service, OS - Other Transmission Service and AD - Out-of-Period Adjustments. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting periods. Provide an explanation in a footnote for each adjustment. See General Instruction for definitions of codes.

Line No.	Payment By (Company of Public Authority) (Footnote Affiliation) (a)	Energy Received From (Company of Public Authority) (Footnote Affiliation) (b)	Energy Delivered To (Company of Public Authority) (Footnote Affiliation) (c)	Statistical Classification (d)
1	Midwest ISO	Midwest ISO	Midwest ISO	AD
2	East Kentucky Power Cooperative	East Kentucky Power Cooperative	East Kentucky Power Cooperative	FNO
3	East Kentucky Power Cooperative	East Kentucky Power Cooperative	East Kentucky Power Cooperative	SFP
4	East Kentucky Power Cooperative	East Kentucky Power Cooperative	East Kentucky Power Cooperative	NF
5	Tennessee Valley Authority	Tennessee Valley Authority	Tennessee Valley Authority	OLF
6	Tennessee Valley Authority	Tennessee Valley Authority	Tennessee Valley Authority	NF
7	Tennessee Valley Authority	Tennessee Valley Authority	Tennessee Valley Authority	SFP
8	Tennessee Valley Authority	Tennessee Valley Authority	Tennesse Valley Authority	NF
9	Big Rivers Electric Corporation	Big Rivers Electric Corporation	Big Rivers Electric Corporation	NF
10	KU/LG&E	Various	Various	NF
11	KU/LG&E	Various	Various	SFP
12	KU/LG&E	Various	Various	LFP
13	Cargill Power Markets, LLC	Various	Various	SFP
14	Cargill Power Markets, LLC	Various	Various	NF
15	Constellation Energy Commodities Group,	PJM	Tennessee Valley Authority	SFP
16				
17				
18				
19				
20				
21				
22				
23				
24				
25				
26				
27				
28				
29				
30				
31				
32				
33				
34				
	TOTAL			

Name of Respondent Kentucky Utilities Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2008/Q4

TRANSMISSION OF ELECTRICITY FOR OTHERS (Account 456)(Continued)
(Including transactions reffered to as 'wheeling')

5. In column (e), identify the FERC Rate Schedule or Tariff Number, On separate lines, list all FERC rate schedules or contract designations under which service, as identified in column (d), is provided.
6. Report receipt and delivery locations for all single contract path, "point to point" transmission service. In column (f), report the designation for the substation, or other appropriate identification for where energy was received as specified in the contract. In column (g) report the designation for the substation, or other appropriate identification for where energy was delivered as specified in the contract.
7. Report in column (h) the number of megawatts of billing demand that is specified in the firm transmission service contract. Demand reported in column (h) must be in megawatts. Footnote any demand not stated on a megawatts basis and explain.
8. Report in column (i) and (j) the total megawatthours received and delivered.

FERC Rate Schedule of Tariff Number (e)	Point of Receipt (Subsatation or Other Designation) (f)	Point of Delivery (Substation or Other Designation) (g)	Billing Demand (MW) (h)	TRANSFER OF ENERGY MegaWatt Hours Received (i)	TRANSFER OF ENERGY MegaWatt Hours Delivered (j)	Line No.
N/A	Midwest ISO	N/A				1
Vol 1 SA 4	East Kentucky Power	East Kentucky Power	329	2,139,815	2,076,823	2
Vol 1	East Kentucky Power	East Kentucky Power		1,219	1,184	3
Vol 1	East Kentucky Power	East Kentucky Power		6,084	5,906	4
93	TVA	TVA	50	310,854	304,571	5
93	TVA	TVA		1,451	1,451	6
Vol 1	TVA	TVA		173	131	7
Vol 1	TVA	Various		2,265	2,554	8
Vol 1	East Kentucky Power	Big Rivers Electric		1,312	1,312	9
Vol 1	Various	Various				10
Vol 1	Various	Various	101			11
Vol 1	Various	Various	89			12
Vol 1	Various	Various		5,062	4,896	13
Vol 1	Various	Various		9,932	9,626	14
Vol 1	PJM	TVA		4,236	4,079	15
						16
						17
						18
						19
						20
						21
						22
						23
						24
						25
						26
						27
						28
						29
						30
						31
						32
						33
						34
			569	2,482,403	2,412,533	

BLANK

Name of Respondent Kentucky Utilities Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2008/Q4

TRANSMISSION OF ELECTRICITY FOR OTHERS (Account 456) (Continued)
(Including transactions reffered to as 'wheeling')

9. In column (k) through (n), report the revenue amounts as shown on bills or vouchers. In column (k), provide revenues from demand charges related to the billing demand reported in column (h). In column (l), provide revenues from energy charges related to the amount of energy transferred. In column (m), provide the total revenues from all other charges on bills or vouchers rendered, including out of period adjustments. Explain in a footnote all components of the amount shown in column (m). Report in column (n) the total charge shown on bills rendered to the entity Listed in column (a). If no monetary settlement was made, enter zero (11011) in column (n). Provide a footnote explaining the nature of the non-monetary settlement, including the amount and type of energy or service rendered.
10. The total amounts in columns (i) and (j) must be reported as Transmission Received and Transmission Delivered for annual report purposes only on Page 401, Lines 16 and 17, respectively.
11. Footnote entries and provide explanations following all required data.

REVENUE FROM TRANSMISSION OF ELECTRICITY FOR OTHERS

Demand Charges ($) (k)	Energy Charges ($) (l)	(Other Charges) ($) (m)	Total Revenues ($) (k+l+m) (n)	Line No.
	-85,278		-85,278	1
2,260,686		-11,549	2,249,137	2
	10,854	405	11,259	3
	8,205	291	8,496	4
485,448		-5,855	479,593	5
	9,234	155	9,389	6
656		16	672	7
	908	43	951	8
	2,799	125	2,924	9
	2,815,337	129,753	2,945,090	10
2,036,441		81,530	2,117,971	11
886,226		44,045	930,271	12
50,751	49,257	6,570	106,578	13
	26,902	1,747	28,649	14
	79,074	3,244	82,318	15
				16
				17
				18
				19
				20
				21
				22
				23
				24
				25
				26
				27
				28
				29
				30
				31
				32
				33
				34
5,720,208	**2,917,292**	**250,520**	**8,888,020**	

Schedule Page: 328 Line No.: 1 Column: l
True-up of December 2007 accrual estimate.

Schedule Page: 328 Line No.: 2 Column: m
The total consists of East Kentucky Power Cooperative Schedule 1 and Schedule 2 charges related to firm transmission.

Schedule Page: 328 Line No.: 3 Column: m
The total consists of East Kentucky Power Cooperative Schedule 1 and Schedule 2 charges related to firm transmission.

Schedule Page: 328 Line No.: 4 Column: m
The total consists of East Kentucky Power Cooperative Schedule 1 and Schedule 2 charges related to non-firm transmission.

Schedule Page: 328 Line No.: 5 Column: d
The OLF transmission service agreement between Tennessee Valley Authority and Kentucky Utilities Company has a termination date of 12/31/2011.

Schedule Page: 328 Line No.: 5 Column: m
The total consists of Tennessee Valley Authority Schedule 1 and Schedule 2 charges related to firm transmission.

Schedule Page: 328 Line No.: 6 Column: m
The total consists of Tennessee Valley Authority Schedule 1 and Schedule 2 charges related to non-firm transmission.

Schedule Page: 328 Line No.: 7 Column: m
The total consists of Tennessee Valley Authority Schedule 1 and Schedule 2 charges related to firm transmission.

Schedule Page: 328 Line No.: 8 Column: m
The total consists of Tennessee Valley Authority Schedule 1 and Schedule 2 charges related to non-firm transmission.

Schedule Page: 328 Line No.: 9 Column: m
The total consists of Big Rivers Electric Corporation Schedule 1 and Schedule 2 charges related to non-firm transmission.

Schedule Page: 328 Line No.: 10 Column: a
The intercompany purchases between Kentucky Utilities Company and Louisville Gas & Electric Company take place under the Open Access Transmission Tariff with allocations determined by the Transmission Coordination Agreement between the Companies. Both the Tariff and the Transmission Coordination Agreement are evergreen (have no termination date). Kentucky Utilities Company and Louisville Gas and Electric Company are both owned by E.ON U.S. LLC.

Schedule Page: 328 Line No.: 10 Column: m
The total consists of Schedule 1 and Schedule 2 charges related to various counterparties.

Schedule Page: 328 Line No.: 11 Column: a
The intercompany purchases between Kentucky Utilities Company and Louisville Gas & Electric Company take place under the Open Access Transmission Tariff with allocations determined by the Transmission Coordination Agreement between the Companies. Both the Tariff and the Transmission Coordination Agreement are evergreen (have no termination date). Kentucky Utilities Company and Louisville Gas and Electric Company are both owned by E.ON U.S. LLC.

Schedule Page: 328 Line No.: 11 Column: m
The total consists of Schedule 1 and Schedule 2 charges related to various counterparties.

Schedule Page: 328 Line No.: 12 Column: a
The intercompany purchases between Kentucky Utilities Company and Louisville Gas & Electric Company take place under the Open Access Transmission Tariff with allocations determined by the Transmission Coordination Agreement between the Companies. Both the Tariff and the Transmission Coordination Agreement are evergreen (have no termination date). Kentucky Utilities Company and Louisville Gas and Electric Company are both owned by E.ON U.S. LLC.

Schedule Page: 328 Line No.: 12 Column: d
The LFP intercompany purchases between Kentucky Utilities Company and Louisville Gas & Electric Company take place under the Open Access Transmission Tariff with allocations determined by the Transmission Coordination Agreement between the Companies. Both the Tariff and the Transmission Coordination Agreement are evergreen (have no termination date).

Schedule Page: 328 Line No.: 12 Column: m
The total consists of Schedule 1 and Schedule 2 charges related to various counterparties.

Schedule Page: 328 Line No.: 13 Column: m

The total consists of Cargill Power Markets, LLC Schedule 1 and Schedule 2 charges.

Schedule Page: 328 Line No.: 14 Column: m

The total consists of Cargill Power Markets, LLC Schedule 1 and Schedule 2 charges.

Schedule Page: 328 Line No.: 15 Column: m

The total consists of Constellation Energy Commodities Group, Inc. Schedule 1 and Schedule 2 charges.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Utilities Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2008/Q4

TRANSMISSION OF ELECTRICITY BY OTHERS (Account 565)
(Including transactions referred to as "wheeling")

1. Report all transmission, i.e. wheeling or electricity provided by other electric utilities, cooperatives, municipalities, other public authorities, qualifying facilities, and others for the quarter.
2. In column (a) report each company or public authority that provided transmission service. Provide the full name of the company, abbreviate if necessary, but do not truncate name or use acronyms. Explain in a footnote any ownership interest in or affiliation with the transmission service provider. Use additional columns as necessary to report all companies or public authorities that provided transmission service for the quarter reported.
3. In column (b) enter a Statistical Classification code based on the original contractual terms and conditions of the service as follows: FNS - Firm Network Transmission Service for Self, LFP - Long-Term Firm Point-to-Point Transmission Reservations. OLF - Other Long-Term Firm Transmission Service, SFP - Short-Term Firm Point-to- Point Transmission Reservations, NF - Non-Firm Transmission Service, and OS - Other Transmission Service. See General Instructions for definitions of statistical classifications.
4. Report in column (c) and (d) the total megawatt hours received and delivered by the provider of the transmission service.
5. Report in column (e), (f) and (g) expenses as shown on bills or vouchers rendered to the respondent. In column (e) report the demand charges and in column (f) energy charges related to the amount of energy transferred. On column (g) report the total of all other charges on bills or vouchers rendered to the respondent, including any out of period adjustments. Explain in a footnote all components of the amount shown in column (g). Report in column (h) the total charge shown on bills rendered to the respondent. If no monetary settlement was made, enter zero in column (h). Provide a footnote explaining the nature of the non-monetary settlement, including the amount and type of energy or service rendered.
6. Enter "TOTAL" in column (a) as the last line.
7. Footnote entries and provide explanations following all required data.

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	TRANSFER OF ENERGY Magawatt-hours Received (c)	Magawatt-hours Delivered (d)	EXPENSES FOR TRANSMISSION OF ELECTRICITY BY OTHERS Demand Charges ($) (e)	Energy Charges ($) (f)	Other Charges ($) (g)	Total Cost of Transmission ($) (h)
1	Midwest ISO	NF	276,483	276,483		1,358,336	157,042	1,515,378
2	Midwest ISO	AD				11,575	-8,510	3,065
3	East Kentucky Power	LFP			1,728,254		125,825	1,854,079
4	East Kentucky Power	AD			-1,613		10,963	9,350
5	Louisville Gas & Elec	LFP	190,129	190,129	334,847		25,812	360,659
6	Louisville Gas & Elec	SFP	126,291	126,291	685,114		47,882	732,996
7	Louisville Gas & Elec	NF	502,218	502,218		1,201,407	108,661	1,310,068
8	Louisville Gas & Elec	AD	-16,251	-16,251		-42,864	-5,825	-48,689
9	PJM Interconnect	SFP	10,848	10,848	41,354		1,712	43,066
10	PJM Interconnect	NF	150,708	150,708		101,021	213,901	314,922
11	Tennessee Valley Auth	NF	62,098	62,098		158,237	61,918	220,155
12								
13								
14								
15								
16								
	TOTAL		1,302,524	1,302,524	2,787,956	2,787,712	739,381	6,315,049

Schedule Page: 332 Line No.: 1 Column: g
The total consists of Schedule 1, Schedule 2, and Schedule 26 charges.

Schedule Page: 332 Line No.: 2 Column: f
The total consists of true-ups for prior periods.

Schedule Page: 332 Line No.: 2 Column: g
The total consists of true-ups of Schedule 1, Schedule 2 and Schedule 26 charges for prior periods.

Schedule Page: 332 Line No.: 3 Column: b
The LFP transmission service agreement between East Kentucky Power Cooperative and Kentucky Utilities Company and Louisville Gas & Electric Company has a termination date of 9/30/2016.

Schedule Page: 332 Line No.: 3 Column: g
The total consists of Schedule 1 and Schedule 2 charges.

Schedule Page: 332 Line No.: 4 Column: e
The total consists of true-ups for prior periods.

Schedule Page: 332 Line No.: 4 Column: f
The total consists of true-ups for prior periods.

Schedule Page: 332 Line No.: 4 Column: g
The total consists of true-ups of Schedule 1 and Schedule 2 charges for prior periods.

Schedule Page: 332 Line No.: 5 Column: a
Kentucky Utilities Company and Louisville Gas & Electric Company are both owned by E.ON U.S. LLC.

Schedule Page: 332 Line No.: 5 Column: b
LFP intercompany purchases between Kentucky Utilities Company and Louisville Gas & Electric Company take place under the Open Access Transmission Tariff with allocations determined by the Transmission Coordination Agreement between the Companies. Both the Tariff and the Transmission Coordination Agreement are evergreen (have no termination date).

Schedule Page: 332 Line No.: 5 Column: g
The total consists of Schedule 1 and Schedule 2 charges.

Schedule Page: 332 Line No.: 6 Column: a
Kentucky Utilities Company and Louisville Gas & Electric Company are both owned by E.ON U.S. LLC.

Schedule Page: 332 Line No.: 6 Column: g
The total consists of Schedule 1 and Schedule 2 charges.

Schedule Page: 332 Line No.: 7 Column: a
Kentucky Utilities Company and Louisville Gas & Electric Company are both owned by E.ON U.S. LLC.

Schedule Page: 332 Line No.: 7 Column: g
The total consists of Schedule 1 and Schedule 2 charges.

Schedule Page: 332 Line No.: 8 Column: a
Kentucky Utilities Company and Louisville Gas & Electric Company are both owned by E.ON U.S. LLC.

Schedule Page: 332 Line No.: 8 Column: c
The total consists of true-ups for prior periods.

Schedule Page: 332 Line No.: 8 Column: d
The total consists of true-ups for prior periods.

Schedule Page: 332 Line No.: 8 Column: f
The total consists of true-ups for prior periods.

Schedule Page: 332 Line No.: 8 Column: g
The total consists of true-ups of Schedule 1 and Schedule 2 charges for prior periods.

Schedule Page: 332 Line No.: 9 Column: g
The total consists of Schedule 1, Schedule 2, Black Start service, and charges for other non-firm point to point without energy.

Schedule Page: 332 Line No.: 10 Column: g
The total consists of Schedule 1, Schedule 2, Black Start service, and charges for other non-firm point to point without energy.

Schedule Page: 332 Line No.: 11 Column: g
The total consists of Schedule 1 and Schedule 2 charges.

BLANK

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Utilities Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2008/Q4

MISCELLANEOUS GENERAL EXPENSES (Account 930.2) (ELECTRIC)

Line No.	Description (a)	Amount (b)
1	Industry Association Dues	378,191
2	Nuclear Power Research Expenses	
3	Other Experimental and General Research Expenses	959,651
4	Pub & Dist Info to Stkhldrs...expn servicing outstanding Securities	
5	Oth Expn >=5,000 show purpose, recipient, amount. Group if < $5,000	
6	Water Use Fees	127,128
7	Broker Fees	24,752
8	Marketing Research & Consulting Expenses	
9	Schmidt Consulting	120,500
10	JD Power and Associates	48,500
11	Marketing Endeavors	31,200
12	JP Morgan Chase Bank	13,980
13	Guideline	9,600
14	Management Consulting	8,431
15	Chartwell	6,998
16	Miscellaneous - Mktg & Consulting Expenses	1,101
17	Miscellaneous	8,052
18		
19		
20		
21		
22		
23		
24		
25		
26		
27		
28		
29		
30		
31		
32		
33		
34		
35		
36		
37		
38		
39		
40		
41		
42		
43		
44		
45		
46	TOTAL	1,738,084

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Utilities Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2008/Q4

DEPRECIATION AND AMORTIZATION OF ELECTRIC PLANT (Account 403, 404, 405)
(Except amortization of aquisition adjustments)

1. Report in section A for the year the amounts for : (b) Depreciation Expense (Account 403; (c) Depreciation Expense for Asset Retirement Costs (Account 403.1; (d) Amortization of Limited-Term Electric Plant (Account 404); and (e) Amortization of Other Electric Plant (Account 405).
2. Report in Section 8 the rates used to compute amortization charges for electric plant (Accounts 404 and 405). State the basis used to compute charges and whether any changes have been made in the basis or rates used from the preceding report year.
3. Report all available information called for in Section C every fifth year beginning with report year 1971, reporting annually only changes to columns (c) through (g) from the complete report of the preceding year.
Unless composite depreciation accounting for total depreciable plant is followed, list numerically in column (a) each plant subaccount, account or functional classification, as appropriate, to which a rate is applied. Identify at the bottom of Section C the type of plant included in any sub-account used.
In column (b) report all depreciable plant balances to which rates are applied showing subtotals by functional Classifications and showing composite total. Indicate at the bottom of section C the manner in which column balances are obtained. If average balances, state the method of averaging used.
For columns (c), (d), and (e) report available information for each plant subaccount, account or functional classification Listed in column (a). If plant mortality studies are prepared to assist in estimating average service Lives, show in column (f) the type mortality curve selected as most appropriate for the account and in column (g), if available, the weighted average remaining life of surviving plant. If composite depreciation accounting is used, report available information called for in columns (b) through (g) on this basis.
4. If provisions for depreciation were made during the year in addition to depreciation provided by application of reported rates, state at the bottom of section C the amounts and nature of the provisions and the plant items to which related.

A. Summary of Depreciation and Amortization Charges

Line No.	Functional Classification (a)	Depreciation Expense (Account 403) (b)	Depreciation Expense for Asset Retirement Costs (Account 403.1) (c)	Amortization of Limited Term Electric Plant (Account 404) (d)	Amortization of Other Electric Plant (Acc 405) (e)	Total (f)
1	Intangible Plant			5,229,656		5,229,656
2	Steam Production Plant	58,478,961	331,380			58,810,341
3	Nuclear Production Plant					
4	Hydraulic Production Plant-Conventional	183,473	52			183,525
5	Hydraulic Production Plant-Pumped Storage					
6	Other Production Plant	16,479,269	2,436			16,481,705
7	Transmission Plant	15,505,505	180			15,505,685
8	Distribution Plant	35,108,289	166			35,108,455
9	Regional Transmission and Market Operation					
10	General Plant	5,025,298				5,025,298
11	Common Plant-Electric					
12	TOTAL	130,780,795	334,214	5,229,656		136,344,665

B. Basis for Amortization Charges

ACCOUNT	RATE	PLANT BALANCE @ 12/31/2008	AMORTIZATION
130200	0 - 5% (1)	83,453	1,874
130300	20%	27,760,617	5,227,782

Notes:
(1) Amortization rates vary from 0 to 5%

Name of Respondent Kentucky Utilities Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2008/Q4

DEPRECIATION AND AMORTIZATION OF ELECTRIC PLANT (Continued)

C. Factors Used in Estimating Depreciation Charges

Line No.	Account No. (a)	Depreciable Plant Base (In Thousands) (b)	Estimated Avg. Service Life (c)	Net Salvage (Percent) (d)	Applied Depr. rates (Percent) (e)	Mortality Curve Type (f)	Average Remaining Life (g)
12							
13							
14							
15							
16							
17							
18							
19							
20							
21							
22							
23							
24							
25							
26							
27							
28							
29							
30							
31							
32							
33							
34							
35							
36							
37							
38							
39							
40							
41							
42							
43							
44							
45							
46							
47							
48							
49							
50							

Name of Respondent Kentucky Utilities Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2008/Q4

REGULATORY COMMISSION EXPENSES

1. Report particulars (details) of regulatory commission expenses incurred during the current year (or incurred in previous years, if being amortized) relating to format cases before a regulatory body, or cases in which such a body was a party.
2. Report in columns (b) and (c), only the current year's expenses that are not deferred and the current year's amortization of amounts deferred in previous years.

Line No.	Description (Furnish name of regulatory commission or body the docket or case number and a description of the case) (a)	Assessed by Regulatory Commission (b)	Expenses of Utility (c)	Total Expense for Current Year (b) + (c) (d)	Deferred in Account 182.3 at Beginning of Year (e)
1	Federal Energy Regulatory Commission				
2	Annual Charge	527,296		527,296	
3	2008 Rate Case		649,691	649,691	
4					
5	Tennessee Regulatory Authority				
6	2008 Rate Filing		15,626	15,626	
7					
8	Kentucky Public Service Commission				
9	2008 Rate Case				
10					
11					
12					
13					
14					
15					
16					
17					
18					
19					
20					
21					
22					
23					
24					
25					
26					
27					
28					
29					
30					
31					
32					
33					
34					
35					
36					
37					
38					
39					
40					
41					
42					
43					
44					
45					
46	TOTAL	527,296	665,317	1,192,613	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Utilities Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2008/Q4

REGULATORY COMMISSION EXPENSES (Continued)

3. Show in column (k) any expenses incurred in prior years which are being amortized. List in column (a) the period of amortization.
4. List in column (f), (g), and (h) expenses incurred during year which were charged currently to income, plant, or other accounts.
5. Minor items (less than $25,000) may be grouped.

EXPENSES INCURRED DURING YEAR				AMORTIZED DURING YEAR			
CURRENTLY CHARGED TO			Deferred to Account 182.3	Contra Account	Amount	Deferred in Account 182.3 End of Year	Line No.
Department (f)	Account No. (g)	Amount (h)	(i)	(j)	(k)	(l)	
							1
Electric	928	527,296					2
Electric	928	649,691					3
							4
							5
Electric	928	15,626					6
							7
							8
Electric	186	1,251,446					9
							10
							11
							12
							13
							14
							15
							16
							17
							18
							19
							20
							21
							22
							23
							24
							25
							26
							27
							28
							29
							30
							31
							32
							33
							34
							35
							36
							37
							38
							39
							40
							41
							42
							43
							44
							45
		2,444,059					46

BLANK

Schedule Page: 350 Line No.: 9 Column: h

Rate Case expenses incurred in Kentucky Public Service Commission (KPSC) Case Nos. 2008-00251 and 2007-00565 will be amortized over 3 years beginning March 2009, by Order of the KPSC dated February 5, 2009.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Utilities Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2008/Q4

RESEARCH, DEVELOPMENT, AND DEMONSTRATION ACTIVITIES

1. Describe and show below costs incurred and accounts charged during the year for technological research, development, and demonstration (R, D & D) project initiated, continued or concluded during the year. Report also support given to others during the year for jointly-sponsored projects.(Identify recipient regardless of affiliation.) For any R, D & D work carried with others, show separately the respondent's cost for the year and cost chargeable to others (See definition of research, development, and demonstration in Uniform System of Accounts).
2. Indicate in column (a) the applicable classification, as shown below:

Classifications:

A. Electric R, D & D Performed Internally:
- (1) Generation
  - a. hydroelectric
    - i. Recreation fish and wildlife
    - ii Other hydroelectric
  - b. Fossil-fuel steam
  - c. Internal combustion or gas turbine
  - d. Nuclear
  - e. Unconventional generation
  - f. Siting and heat rejection
- (2) Transmission
  - a. Overhead
  - b. Underground
- (3) Distribution
- (4) Regional Transmission and Market Operation
- (5) Environment (other than equipment)
- (6) Other (Classify and include Items in excess of $5,000.)
- (7) Total Cost Incurred

B. Electric, R, D & D Performed Externally:
- (1) Research Support to the electrical Research Council or the Electric Power Research Institute

Line No.	Classification (a)	Description (b)
1	EPRI B(1)	2008 Membership fees
2	EPRI B(1)	2008 Membership fees
3	EPRI B(1)	2008 Membership fees
4	Edison Electric Institute B(2)	2008 Utility Air Regulatory Group fees
5	Univ. of Ky - Research Foundation B(4)	Carbon Management Research Program
6	Ky Consortium for Carbon Storage B(4)	2008 Carbon Storage Project
7	UofL - Center for Infrastructure Research B(4)	2009 Annual Membership
8	UofL - Center for Infrastructure Research B(4)	2009 Annual Membership
9	Total Cost	
10		
11		
12		
13		
14		
15		
16		
17		
18		
19		
20		
21		
22		
23		
24		
25		
26		
27		
28		
29		
30		
31		
32		
33		
34		
35		
36		
37		

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Utilities Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2008/Q4

RESEARCH, DEVELOPMENT, AND DEMONSTRATION ACTIVITIES (Continued)

(2) Research Support to Edison Electric Institute
(3) Research Support to Nuclear Power Groups
(4) Research Support to Others (Classify)
(5) Total Cost Incurred

3. Include in column (c) all R, D & D items performed internally and in column (d) those items performed outside the company costing $5,000 or more, briefly describing the specific area of R, D & D (such as safety, corrosion control, pollution, automation, measurement, insulation, type of appliance, etc.). Group items under $5,000 by classifications and indicate the number of items grouped. Under Other, (A (6) and B (4)) classify items by type of R, D & D activity.
4. Show in column (e) the account number charged with expenses during the year or the account to which amounts were capitalized during the year, listing Account 107, Construction Work in Progress, first. Show in column (f) the amounts related to the account charged in column (e)
5. Show in column (g) the total unamortized accumulating of costs of projects. This total must equal the balance in Account 188, Research, Development, and Demonstration Expenditures, Outstanding at the end of the year.
6. If costs have not been segregated for R, D &D activities or projects, submit estimates for columns (c), (d), and (f) with such amounts identified by "Est."
7. Report separately research and related testing facilities operated by the respondent.

Costs Incurred Internally Current Year (c)	Costs Incurred Externally Current Year (d)	AMOUNTS CHARGED IN CURRENT YEAR Account (e)	AMOUNTS CHARGED IN CURRENT YEAR Amount (f)	Unamortized Accumulation (g)	Line No.
	945,068	930	945,068		1
	171,458	923	171,458		2
	25,522	908	25,522		3
	378,191	930	378,191		4
	250,000	426	250,000		5
	130,014	182	130,014		6
	14,583	930	14,583		7
	10,417	165	10,417		8
	1,925,253		1,925,253		9
					10
					11
					12
					13
					14
					15
					16
					17
					18
					19
					20
					21
					22
					23
					24
					25
					26
					27
					28
					29
					30
					31
					32
					33
					34
					35
					36

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Utilities Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2008/Q4

DISTRIBUTION OF SALARIES AND WAGES

Report below the distribution of total salaries and wages for the year. Segregate amounts originally charged to clearing accounts to Utility Departments, Construction, Plant Removals, and Other Accounts, and enter such amounts in the appropriate lines and columns provided. In determining this segregation of salaries and wages originally charged to clearing accounts, a method of approximation giving substantially correct results may be used.

Line No.	Classification (a)	Direct Payroll Distribution (b)	Allocation of Payroll charged for Clearing Accounts (c)	Total (d)
1	Electric			
2	Operation			
3	Production	16,799,968		
4	Transmission	2,025,262		
5	Regional Market			
6	Distribution	8,600,436		
7	Customer Accounts	7,181,104		
8	Customer Service and Informational	436,244		
9	Sales			
10	Administrative and General	12,370,059		
11	TOTAL Operation (Enter Total of lines 3 thru 10)	47,413,073		
12	Maintenance			
13	Production	11,170,015		
14	Transmission	633,192		
15	Regional Market			
16	Distribution	6,071,029		
17	Administrative and General	2,631,205		
18	TOTAL Maintenance (Total of lines 13 thru 17)	20,505,441		
19	Total Operation and Maintenance			
20	Production (Enter Total of lines 3 and 13)	27,969,983		
21	Transmission (Enter Total of lines 4 and 14)	2,658,454		
22	Regional Market (Enter Total of Lines 5 and 15)			
23	Distribution (Enter Total of lines 6 and 16)	14,671,465		
24	Customer Accounts (Transcribe from line 7)	7,181,104		
25	Customer Service and Informational (Transcribe from line 8)	436,244		
26	Sales (Transcribe from line 9)			
27	Administrative and General (Enter Total of lines 10 and 17)	15,001,264		
28	TOTAL Oper. and Maint. (Total of lines 20 thru 27)	67,918,514	16,972,822	84,891,336
29	Gas			
30	Operation			
31	Production-Manufactured Gas			
32	Production-Nat. Gas (Including Expl. and Dev.)			
33	Other Gas Supply			
34	Storage, LNG Terminaling and Processing			
35	Transmission			
36	Distribution			
37	Customer Accounts			
38	Customer Service and Informational			
39	Sales			
40	Administrative and General			
41	TOTAL Operation (Enter Total of lines 31 thru 40)			
42	Maintenance			
43	Production-Manufactured Gas			
44	Production-Natural Gas (Including Exploration and Development)			
45	Other Gas Supply			
46	Storage, LNG Terminaling and Processing			
47	Transmission			

Name of Respondent Kentucky Utilities Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2008/Q4

DISTRIBUTION OF SALARIES AND WAGES (Continued)

Line No.	Classification (a)	Direct Payroll Distribution (b)	Allocation of Payroll charged for Clearing Accounts (c)	Total (d)
48	Distribution			
49	Administrative and General			
50	TOTAL Maint. (Enter Total of lines 43 thru 49)			
51	Total Operation and Maintenance			
52	*Production-Manufactured Gas (Enter Total of lines 31 and 43)*			
53	Production-Natural Gas (Including Expl. and Dev.) (Total lines 32,			
54	Other Gas Supply (Enter Total of lines 33 and 45)			
55	Storage, LNG Terminaling and Processing (Total of lines 31 thru			
56	Transmission (Lines 35 and 47)			
57	Distribution (Lines 36 and 48)			
58	Customer Accounts (Line 37)			
59	Customer Service and Informational (Line 38)			
60	Sales (Line 39)			
61	Administrative and General (Lines 40 and 49)			
62	TOTAL Operation and Maint. (Total of lines 52 thru 61)			
63	Other Utility Departments			
64	Operation and Maintenance			
65	TOTAL All Utility Dept. (Total of lines 28, 62, and 64)	67,918,514	16,972,822	84,891,336
66	Utility Plant			
67	Construction (By Utility Departments)			
68	Electric Plant	19,659,121	13,231,962	32,891,083
69	Gas Plant			
70	Other (provide details in footnote):			
71	TOTAL Construction (Total of lines 68 thru 70)	19,659,121	13,231,962	32,891,083
72	Plant Removal (By Utility Departments)			
73	Electric Plant	828,960	454,679	1,283,639
74	Gas Plant			
75	Other (provide details in footnote):			
76	TOTAL Plant Removal (Total of lines 73 thru 75)	828,960	454,679	1,283,639
77	Other Accounts (Specify, provide details in footnote):			
78	Accounts Receivable (work done for others)	6,975,394	1,042,790	8,018,184
79	Miscellaneous Deferred Debits & Preliminary Survey	342,461	93,280	435,741
80	Regulatory Asset	391,645		391,645
81	Certain Civic, Political and Related Activities and Other	355,101	104,005	459,106
82				
83				
84				
85				
86				
87				
88				
89				
90				
91				
92				
93				
94				
95	TOTAL Other Accounts	8,064,601	1,240,075	9,304,676
96	TOTAL SALARIES AND WAGES	96,471,196	31,899,538	128,370,734

BLANK

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Utilities Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2008/Q4

AMOUNTS INCLUDED IN ISO/RTO SETTLEMENT STATEMENTS

1. The respondent shall report below the details called for concerning amounts it recorded in Account 555, Purchase Power, and Account 447, Sales for Resale, for items shown on ISO/RTO Settlement Statements. Transactions should be separately netted for each ISO/RTO administered energy market for purposes of determining whether an entity is a net seller or purchaser in a given hour. Net megawatt hours are to be used as the basis for determining whether a net purchase or sale has occurred. In each monthly reporting period, the hourly sale and purchase net amounts are to be aggregated and separately reported in Account 447, Sales for Resale, or Account 555, Purchased Power, respectively.

Line No.	Description of Item(s) (a)	Balance at End of Quarter 1 (b)	Balance at End of Quarter 2 (c)	Balance at End of Quarter 3 (d)	Balance at End of Year (e)
1	Energy				
2	Net Purchases (Account 555)	11,409,035	21,006,024	27,412,810	27,927,057
3	Net Sales (Account 447)	1,074,396	2,572,148	5,558,858	10,536,309
4	Transmission Rights				
5	Ancillary Services				
6	Other Items (list separately)				
7					
8					
9					
10					
11					
12					
13					
14					
15					
16					
17					
18					
19					
20					
21					
22					
23					
24					
25					
26					
27					
28					
29					
30					
31					
32					
33					
34					
35					
36					
37					
38					
39					
40					
41					
42					
43					
44					
45					
46	TOTAL	12,483,431	23,578,172	32,971,668	38,463,366

Schedule Page: 397 Line No.: 2 Column: b

The amount reflects transactions recorded in accordance with Kentucky Utilities Company's Power Supply System Agreement with Louisville Gas and Electric Company, as approved by the Kentucky Public Service Commission in October 1997, in which purchases and sales are calculated based on joint dispatch of the Companies' units. Such calculations do not distinguish between purchases and sales made in the Day Ahead and Real Time markets. Absent such a Power Supply System Agreement, the purchase amount recorded in accordance with FERC Order No. 668-A would have been $11,335,803.

Schedule Page: 397 Line No.: 2 Column: c

The amount reflects transactions recorded in accordance with Kentucky Utilities Company's Power Supply System Agreement with Louisville Gas and Electric Company, as approved by the Kentucky Public Service Commission in October 1997, in which purchases and sales are calculated based on joint dispatch of the Companies' units. Such calculations do not distinguish between purchases and sales made in the Day Ahead and Real Time markets. Absent such a Power Supply System Agreement, the purchase amount recorded in accordance with FERC Order No. 668-A would have been $20,902,380.

Schedule Page: 397 Line No.: 2 Column: d

The amount reflects transactions recorded in accordance with Kentucky Utilities Company's Power Supply System Agreement with Louisville Gas and Electric Company, as approved by the Kentucky Public Service Commission in October 1997, in which purchases and sales are calculated based on joint dispatch of the Companies' units. Such calculations do not distinguish between purchases and sales made in the Day Ahead and Real Time markets. Absent such a Power Supply System Agreement, the purchase amount recorded in accordance with FERC Order No. 668-A would have been $27,295,723.

Schedule Page: 397 Line No.: 2 Column: e

The amount reflects transactions recorded in accordance with Kentucky Utilities Company's Power Supply System Agreement with Louisville Gas and Electric Company, as approved by the Kentucky Public Service Commission in October 1997, in which purchases and sales are calculated based on joint dispatch of the Companies' units. Such calculations do not distinguish between purchases and sales made in the Day Ahead and Real Time markets. Absent such a Power Supply System Agreement, the purchase amount recorded in accordance with FERC Order No. 668-A would have been $27,796,364.

Schedule Page: 397 Line No.: 3 Column: b

The amount reflects transactions recorded in accordance with Kentucky Utilities Company's Power Supply System Agreement with Louisville Gas and Electric Company, as approved by the Kentucky Public Service Commission in October 1997, in which purchases and sales are calculated based on joint dispatch of the Companies' units. Such calculations do not distinguish between purchases and sales made in the Day Ahead and Real Time markets. Absent such a Power Supply System Agreement, the sale amount recorded in accordance with FERC Order No. 668-A would have been $1,068,308.

Schedule Page: 397 Line No.: 3 Column: c

The amount reflects transactions recorded in accordance with Kentucky Utilities Company's Power Supply System Agreement with Louisville Gas and Electric Company, as approved by the Kentucky Public Service Commission in October 1997, in which purchases and sales are calculated based on joint dispatch of the Companies' units. Such calculations do not distinguish between purchases and sales made in the Day Ahead and Real Time markets. Absent such a Power Supply System Agreement, the sale amount recorded in accordance with FERC Order No. 668-A would have been $2,564,200.

Schedule Page: 397 Line No.: 3 Column: d

The amount reflects transactions recorded in accordance with Kentucky Utilities Company's Power Supply System Agreement with Louisville Gas and Electric Company, as approved by the Kentucky Public Service Commission in October 1997, in which purchases and sales are calculated based on joint dispatch of the Companies' units. Such calculations do not distinguish between purchases and sales made in the Day Ahead and Real Time markets. Absent such a Power Supply System Agreement, the sale amount recorded in accordance with FERC Order No. 668-A would have been $5,549,129.

Schedule Page: 397 Line No.: 3 Column: e

The amount reflects transactions recorded in accordance with Kentucky Utilities Company's Power Supply System Agreement with Louisville Gas and Electric Company, as approved by the Kentucky Public Service Commission in October 1997, in which purchases and sales are calculated based on joint dispatch of the Companies' units. Such calculations do not distinguish between purchases and sales made in the Day Ahead and Real Time markets. Absent such a Power Supply System Agreement, the sale amount recorded in accordance with FERC Order No. 668-A would have been $10,521,934.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Utilities Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2008/Q4

PURCHASES AND SALES OF ANCILLARY SERVICES

Report the amounts for each type of ancillary service shown in column (a) for the year as specified in Order No. 888 and defined in the respondents Open Access Transmission Tariff.

In columns for usage, report usage-related billing determinant and the unit of measure.

(1) On line 1 columns (b), (c), (d), (e), (f) and (g) report the amount of ancillary services purchased and sold during the year.

(2) On line 2 columns (b) (c), (d), (e), (f), and (g) report the amount of reactive supply and voltage control services purchased and sold during the year.

(3) On line 3 columns (b) (c), (d), (e), (f), and (g) report the amount of regulation and frequency response services purchased and sold during the year.

(4) On line 4 columns (b), (c), (d), (e), (f), and (g) report the amount of energy imbalance services purchased and sold during the year.

(5) On lines 5 and 6, columns (b), (c), (d), (e), (f), and (g) report the amount of operating reserve spinning and supplement services purchased and sold during the period.

(6) On line 7 columns (b), (c), (d), (e), (f), and (g) report the total amount of all other types ancillary services purchased or sold during the year. Include in a footnote and specify the amount for each type of other ancillary service provided.

		Amount Purchased for the Year			Amount Sold for the Year		
		Usage - Related Billing Determinant			Usage - Related Billing Determinant		
Line No.	Type of Ancillary Service (a)	Number of Units (b)	Unit of Measure (c)	Dollars (d)	Number of Units (e)	Unit of Measure (f)	Dollars (g)
1	Scheduling, System Control and Dispatch	1,302,524	MWH	314,369	2,482,403	MWH	75,986
2	Reactive Supply and Voltage	1,302,524	MWH	324,678	2,482,403	MWH	174,534
3	Regulation and Frequency Response						
4	Energy Imbalance						
5	Operating Reserve - Spinning						
6	Operating Reserve - Supplement						
7	Other			100,334			
8	Total (Lines 1 thru 7)	2,605,048		739,381	4,964,806		250,520

Schedule Page: 398 Line No.: 7 Column: b

Amounts are not associated with a number of units or a unit of measure.

Schedule Page: 398 Line No.: 7 Column: d

This amount consists of PJM non-energy related charges related to non-firm point to point transmission services and Black Start charges. This amount also includes The Midwest ISO's Schedule 26 Charges (Network Upgrade Charge from Transmission Expansion Plan).

PJM Other Charges	$ 73,314
MISO Schedule 26	27,020
	$100,334

BLANK

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Utilities Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2008/Q4

MONTHLY TRANSMISSION SYSTEM PEAK LOAD

(1) Report the monthly peak load on the respondent's transmission system. If the respondent has two or more power systems which are not physically integrated, furnish the required information for each non-integrated system.
(2) Report on Column (b) by month the transmission system's peak load.
(3) Report on Columns (c) and (d) the specified information for each monthly transmission - system peak load reported on Column (b).
(4) Report on Columns (e) through (j) by month the system' monthly maximum megawatt load by statistical classifications. See General Instruction for the definition of each statistical classification.

NAME OF SYSTEM: KU

Line No.	Month (a)	Monthly Peak MW - Total (b)	Day of Monthly Peak (c)	Hour of Monthly Peak (d)	Firm Network Service for Self (e)	Firm Network Service for Others (f)	Long-Term Firm Point-to-point Reservations (g)	Other Long-Term Firm Service (h)	Short-Term Firm Point-to-point Reservation (i)	Other Service (j)
1	January	5,196	25	8	4,476	481	89			150
2	February	4,647	11	8	3,938	473	89			147
3	March	4,023	7	20	3,400	412	89			122
4	Total for Quarter 1	13,866			11,814	1,366	267			419
5	April	3,633	15	7	3,089	333	89			122
6	May	3,667	27	17	3,090	324	89			164
7	June	4,690	9	14	3,910	395	89		70	226
8	Total for Quarter 2	11,990			10,089	1,052	267		70	512
9	July	4,696	29	16	3,829	416	89		139	223
10	August	4,560	1	16	3,668	372	89		209	222
11	September	4,382	2	16	3,805	272	89			216
12	Total for Quarter 3	13,638			11,302	1,060	267		348	661
13	October	3,332	15	16	2,894	188	89			161
14	November	4,698	19	9	3,513	421	89		547	128
15	December	5,011	22	9	4,113	406	89		252	151
16	Total for Quarter 4	13,041			10,520	1,015	267		799	440
17	Total Year to Date/Year	52,535			43,725	4,493	1,068		1,217	2,032

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Utilities Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2008/Q4

ELECTRIC ENERGY ACCOUNT

Report below the information called for concerning the disposition of electric energy generated, purchased, exchanged and wheeled during the year.

Line No.	Item (a)	MegaWatt Hours (b)	Line No.	Item (a)	MegaWatt Hours (b)
1	SOURCES OF ENERGY		21	DISPOSITION OF ENERGY	
2	Generation (Excluding Station Use):		22	Sales to Ultimate Consumers (Including Interdepartmental Sales)	19,218,601
3	Steam	17,946,908			
4	Nuclear		23	Requirements Sales for Resale (See instruction 4, page 311.)	1,971,405
5	Hydro-Conventional	50,505			
6	Hydro-Pumped Storage		24	Non-Requirements Sales for Resale (See instruction 4, page 311.)	2,893,713
7	Other	298,123			
8	Less Energy for Pumping		25	Energy Furnished Without Charge	55
9	Net Generation (Enter Total of lines 3 through 8)	18,295,536	26	Energy Used by the Company (Electric Dept Only, Excluding Station Use)	21,841
10	Purchases	7,095,014	27	Total Energy Losses	1,360,367
11	Power Exchanges:		28	TOTAL (Enter Total of Lines 22 Through 27) (MUST EQUAL LINE 20)	25,465,982
12	Received	34,513			
13	Delivered	28,951			
14	Net Exchanges (Line 12 minus line 13)	5,562			
15	Transmission For Other (Wheeling)				
16	Received	2,482,403			
17	Delivered	2,412,533			
18	Net Transmission for Other (Line 16 minus line 17)	69,870			
19	Transmission By Others Losses				
20	TOTAL (Enter Total of lines 9, 10, 14, 18 and 19)	25,465,982			

Name of Respondent Kentucky Utilities Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2008/Q4

MONTHLY PEAKS AND OUTPUT

(1) Report the monthly peak load and energy output. If the respondent has two or more power which are not physically integrated, furnish the required information for each non- integrated system.
(2) Report on line 2 by month the system's output in Megawatt hours for each month.
(3) Report on line 3 by month the non-requirements sales for resale. Include in the monthly amounts any energy losses associated with the sales.
(4) Report on line 4 by month the system's monthly maximum megawatt load (60 minute integration) associated with the system.
(5) Report on lines 5 and 6 the specified information for each monthly peak load reported on line 4.

NAME OF SYSTEM: KU

Line No.	Month (a)	Total Monthly Energy (b)	Monthly Non-Requirments Sales for Resale & Associated Losses (c)	MONTHLY PEAK Megawatts (See Instr. 4) (d)	Day of Month (e)	Hour (f)
29	January	2,468,476	213,504	4,476	25	800
30	February	2,091,223	91,340	3,938	11	800
31	March	2,076,280	183,756	3,452	25	700
32	April	1,757,255	138,325	3,087	15	700
33	May	1,847,233	228,430	3,090	27	1700
34	June	2,057,476	152,557	3,910	9	1400
35	July	2,182,025	170,840	3,943	21	1400
36	August	2,118,058	137,419	3,699	5	1600
37	September	2,051,977	256,286	3,832	3	1500
38	October	2,105,423	448,486	3,069	30	800
39	November	2,309,619	550,419	3,567	19	900
40	December	2,400,937	322,351	4,113	22	900
41	TOTAL	25,465,982	2,893,713			

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Utilities Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2008/Q4

STEAM-ELECTRIC GENERATING PLANT STATISTICS (Large Plants)

1. Report data for plant in Service only. 2. Large plants are steam plants with installed capacity (name plate rating) of 25,000 Kw or more. Report in this page gas-turbine and internal combustion plants of 10,000 Kw or more, and nuclear plants. 3. Indicate by a footnote any plant leased or operated as a joint facility. 4. If net peak demand for 60 minutes is not available, give data which is available, specifying period. 5. If any employees attend more than one plant, report on line 11 the approximate average number of employees assignable to each plant. 6. If gas is used and purchased on a therm basis report the Btu content or the gas and the quantity of fuel burned converted to Mct. 7. Quantities of fuel burned (Line 38) and average cost per unit of fuel burned (Line 41) must be consistent with charges to expense accounts 501 and 547 (Line 42) as show on Line 20. 8. If more than one fuel is burned in a plant furnish only the composite heat rate for all fuels burned.

Line No.	Item (a)	Plant Name: *Tyrone* (b)			Plant Name: *Green River* (c)		
1	Kind of Plant (Internal Comb, Gas Turb, Nuclear			Steam			Steam
2	Type of Constr (Conventional, Outdoor, Boiler, etc)			Conventional			Conventional
3	Year Originally Constructed			1947			1950
4	Year Last Unit was Installed			1971			1959
5	Total Installed Cap (Max Gen Name Plate Ratings-MW)			75.00			189.00
6	Net Peak Demand on Plant - MW (60 minutes)			75			176
7	Plant Hours Connected to Load			6449			7376
8	Net Continuous Plant Capability (Megawatts)			73			173
9	When Not Limited by Condenser Water			73			173
10	When Limited by Condenser Water			0			0
11	Average Number of Employees			26			67
12	Net Generation, Exclusive of Plant Use - KWh			355632000			962135000
13	Cost of Plant: Land and Land Rights			53142			30764
14	Structures and Improvements			6124163			9999931
15	Equipment Costs			19594803			55831157
16	Asset Retirement Costs			246752			1074377
17	Total Cost			26018860			66936229
18	Cost per KW of Installed Capacity (line 17/5) Including			346.9181			354.1599
19	Production Expenses: Oper, Supv, & Engr			678571			320173
20	Fuel			14287471			25920637
21	Coolants and Water (Nuclear Plants Only)			0			0
22	Steam Expenses			734516			1394904
23	Steam From Other Sources			0			0
24	Steam Transferred (Cr)			0			0
25	Electric Expenses			158777			1048365
26	Misc Steam (or Nuclear) Power Expenses			360737			874630
27	Rents			0			0
28	Allowances			22925			103658
29	Maintenance Supervision and Engineering			222728			1133056
30	Maintenance of Structures			257846			447009
31	Maintenance of Boiler (or reactor) Plant			626195			2172856
32	Maintenance of Electric Plant			439622			559018
33	Maintenance of Misc Steam (or Nuclear) Plant			133087			95714
34	Total Production Expenses			17922475			34070020
35	Expenses per Net KWh			0.0504			0.0354
36	Fuel: Kind (Coal, Gas, Oil, or Nuclear)	Coal	Oil		Coal	Oil	
37	Unit (Coal-tons/Oil-barrel/Gas-mcf/Nuclear-indicate)	tons	barrels		tons	barrels	
38	Quantity (Units) of Fuel Burned	176178	4404	0	468155	3821	0
39	Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)	12712	3333	0	11735	3333	0
40	Avg Cost of Fuel/unit, as Delvd f.o.b. during year	71.410	110.881	0.000	55.720	130.696	0.000
41	Average Cost of Fuel per Unit Burned	78.327	110.881	0.000	54.301	130.696	0.000
42	Average Cost of Fuel Burned per Million BTU	3.081	18.845	0.000	2.314	22.227	0.000
43	Average Cost of Fuel Burned per KWh Net Gen	0.039	0.000	0.000	0.026	0.000	0.000
44	Average BTU per KWh Net Generation	12595.000	0.000	0.000	11420.000	0.000	0.000

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Utilities Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2008/Q4

STEAM-ELECTRIC GENERATING PLANT STATISTICS (Large Plants)*(Continued)*

9. Items under Cost of Plant are based on U. S. of A. Accounts. Production expenses do not include Purchased Power, System Control and Load Dispatching, and Other Expenses Classified as Other Power Supply Expenses. 10. For IC and GT plants, report Operating Expenses, Account Nos. 547 and 549 on Line 25 "Electric Expenses," and Maintenance Account Nos. 553 and 554 on Line 32, "Maintenance of Electric Plant." Indicate plants designed for peak load service. Designate automatically operated plants. 11. For a plant equipped with combinations of fossil fuel steam, nuclear steam, hydro, internal combustion or gas-turbine equipment, report each as a separate plant. However, if a gas-turbine unit functions in a combined cycle operation with a conventional steam unit, include the gas-turbine with the steam plant. 12. If a nuclear power generating plant, briefly explain by footnote (a) accounting method for cost of power generated including any excess costs attributed to research and development; (b) types of cost units used for the various components of fuel cost; and (c) any other informative data concerning plant type fuel used, fuel enrichment type and quantity for the report period and other physical and operating characteristics of plant.

Plant Name: *EW Brown* (d)	Plant Name: *Ghent* (e)	Plant Name: *Haefling* (f)	Line No.
Steam	Steam	Combustion Turbine	1
Conventional	Conventional	Outdoor	2
1957	1973	1970	3
1971	1984	1970	4
740.00	2226.00	62.00	5
495	1964	21	6
7945	7569	3	7
704	1918	42	8
704	1918	42	9
0	0	0	10
142	217	0	11
4123461000	12505680000	-367000	12
899869	9842885	0	13
27337950	131169787	434853	14
236171016	1516782140	4909804	15
3248171	4657807	0	16
267657006	1662452619	5344657	17
361.6987	746.8341	86.2041	18
1159899	1937928	0	19
115467783	312642607	-189605	20
0	0	0	21
2173067	7995950	0	22
0	0	0	23
0	0	0	24
1582075	2803436	0	25
1975080	7385547	8168	26
0	0	0	27
266587	226648	0	28
1752974	3038368	0	29
1401387	3301797	0	30
5932171	16478674	0	31
2868522	5874697	64251	32
137552	692651	25001	33
134717097	362378303	-92185	34
0.0327	0.0290	0.2512	35

(d)			(e)			(f)			Line No.
Coal	Oil		Coal	Oil		Gas	Oil		36
tons	barrels		tons	barrels		mcf	barrels		37
1787798	9870	0	5705152	44361	0	1723	11	0	38
12102	3333	0	11796	3333	0	1025	3333	0	39
64.730	124.744	0.000	55.530	132.195	0.000	15.096	-19601.328	0.000	40
63.898	124.744	0.000	53.772	132.195	0.000	15.096	-3422.454	0.000	41
2.640	21.215	0.000	2.279	22.482	0.000	14.728	0.000	0.000	42
0.028	0.000	0.000	0.025	0.000	0.000	-0.071	0.000	0.000	43
10494.000	0.000	0.000	10763.000	0.000	0.000	-4812.000	0.000	0.000	44

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Utilities Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2008/Q4

STEAM-ELECTRIC GENERATING PLANT STATISTICS (Large Plants) *(Continued)*

1. Report data for plant in Service only. 2. Large plants are steam plants with installed capacity (name plate rating) of 25,000 Kw or more. Report in this page gas-turbine and internal combustion plants of 10,000 Kw or more, and nuclear plants. 3. Indicate by a footnote any plant leased or operated as a joint facility. 4. If net peak demand for 60 minutes is not available, give data which is available, specifying period. 5. If any employees attend more than one plant, report on line 11 the approximate average number of employees assignable to each plant. 6. If gas is used and purchased on a therm basis report the Btu content or the gas and the quantity of fuel burned converted to Mct. 7. Quantities of fuel burned (Line 38) and average cost per unit of fuel burned (Line 41) must be consistent with charges to expense accounts 501 and 547 (Line 42) as show on Line 20. 8. If more than one fuel is burned in a plant furnish only the composite heat rate for all fuels burned.

Line No.	Item (a)	Plant Name: *Brown CT* (b)	Plant Name: *Paddy's Run 13 CT* (c)
1	Kind of Plant (Internal Comb, Gas Turb, Nuclear	Combustion Turbine	Combustion Turbine
2	Type of Constr (Conventional, Outdoor, Boiler, etc)	Conventional	Conventional
3	Year Originally Constructed	1994	2001
4	Year Last Unit was Installed	2001	2001
5	Total Installed Cap (Max Gen Name Plate Ratings-MW)	781.00	84.00
6	Net Peak Demand on Plant - MW (60 minutes)	517	55
7	Plant Hours Connected to Load	121	51
8	Net Continuous Plant Capability (Megawatts)	836	82
9	When Not Limited by Condenser Water	836	82
10	When Limited by Condenser Water	0	0
11	Average Number of Employees	0	0
12	Net Generation, Exclusive of Plant Use - KWh	47084000	3078000
13	Cost of Plant: Land and Land Rights	275012	0
14	Structures and Improvements	11891044	1910328
15	Equipment Costs	239325183	28148298
16	Asset Retirement Costs	70990	0
17	Total Cost	251562229	30058626
18	Cost per KW of Installed Capacity (line 17/5) Including	322.1027	357.8408
19	Production Expenses: Oper, Supv, & Engr	177861	0
20	Fuel	7963203	699624
21	Coolants and Water (Nuclear Plants Only)	0	0
22	Steam Expenses	0	0
23	Steam From Other Sources	0	0
24	Steam Transferred (Cr)	0	0
25	Electric Expenses	5404	0
26	Misc Steam (or Nuclear) Power Expenses	127549	2114
27	Rents	0	0
28	Allowances	0	0
29	Maintenance Supervision and Engineering	96918	0
30	Maintenance of Structures	157283	0
31	Maintenance of Boiler (or reactor) Plant	0	0
32	Maintenance of Electric Plant	1721711	359886
33	Maintenance of Misc Steam (or Nuclear) Plant	492892	0
34	Total Production Expenses	10742821	1061624
35	Expenses per Net KWh	0.2282	0.3449

Line No.	Item (a)	(b)			(c)		
36	Fuel: Kind (Coal, Gas, Oil, or Nuclear)	Gas	Oil		Gas		
37	Unit (Coal-tons/Oil-barrel/Gas-mcf/Nuclear-indicate)	mcf	barrels		mcf		
38	Quantity (Units) of Fuel Burned	659052	7601	0	33036	0	0
39	Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)	1025	3333	0	1025	0	0
40	Avg Cost of Fuel/unit, as Delvd f.o.b. during year	11.034	90.924	0.000	21.178	0.000	0.000
41	Average Cost of Fuel per Unit Burned	11.034	90.924	0.000	21.178	0.000	0.000
42	Average Cost of Fuel Burned per Million BTU	10.765	15.463	0.000	20.660	0.000	0.000
43	Average Cost of Fuel Burned per KWh Net Gen	0.168	0.185	0.000	0.227	0.000	0.000
44	Average BTU per KWh Net Generation	15581.000	11989.000	0.000	11002.000	0.000	0.000

Name of Respondent Kentucky Utilities Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2008/Q4

STEAM-ELECTRIC GENERATING PLANT STATISTICS (Large Plants)*(Continued)*

9. Items under Cost of Plant are based on U. S. of A. Accounts. Production expenses do not include Purchased Power, System Control and Load Dispatching, and Other Expenses Classified as Other Power Supply Expenses. 10. For IC and GT plants, report Operating Expenses, Account Nos. 547 and 549 on Line 25 "Electric Expenses," and Maintenance Account Nos. 553 and 554 on Line 32, "Maintenance of Electric Plant." Indicate plants designed for peak load service. Designate automatically operated plants. 11. For a plant equipped with combinations of fossil fuel steam, nuclear steam, hydro, internal combustion or gas-turbine equipment, report each as a separate plant. However, if a gas-turbine unit functions in a combined cycle operation with a conventional steam unit, include the gas-turbine with the steam plant. 12. If a nuclear power generating plant, briefly explain by footnote (a) accounting method for cost of power generated including any excess costs attributed to research and development; (b) types of cost units used for the various components of fuel cost; and (c) any other informative data concerning plant type fuel used, fuel enrichment type and quantity for the report period and other physical and operating characteristics of plant.

Plant Name: *Trimble County CT* (d)	Plant Name: (e)	Plant Name: (f)	Line No.
Combustion Turbine			1
Conventional			2
2002			3
2004			4
784.00	0.00	0.00	5
705	0	0	6
533	0	0	7
709	0	0	8
709	0	0	9
0	0	0	10
0	0	0	11
248328000	0	0	12
19912	0	0	13
21745929	0	0	14
194529814	0	0	15
0	0	0	16
216295655	0	0	17
275.8873	0.0000	0.0000	18
0	0	0	19
35607751	0	0	20
0	0	0	21
0	0	0	22
0	0	0	23
0	0	0	24
2346962	0	0	25
12	0	0	26
0	0	0	27
0	0	0	28
9315	0	0	29
0	0	0	30
0	0	0	31
172654	0	0	32
0	0	0	33
38136694	0	0	34
0.1536	0.0000	0.0000	35

Gas									36
mcf									37
2973794	0	0	0	0	0	0	0	0	38
1025	0	0	0	0	0	0	0	0	39
11.974	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	40
11.974	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	41
11.682	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	42
0.143	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	43
12275.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	44

BLANK

Schedule Page: 402 Line No.: 11 Column: f

No production/operation employees are directly assigned to Haefling turbines. Employees from the Tyrone Plant operate and maintain the Haefling turbines.

Schedule Page: 402 Line No.: 20 Column: f

Fuel expenses consist of the following:

Oil used for generation	$ 26,295
Proceeds from the sale of oil inventory	(215,900)
Total	$(189,605)

The oil tank at Haefling was emptied in 2008 to comply with the FERC's inspection requirements. The oil was sold to a third party and revenues were recorded in account 501 to offset fuel expense.

Schedule Page: 402.1 Line No.: -1 Column: e

Pineville Generating Station is fully retired. However, land and ashpond assets amounting to $312,711 remain on the books.

Schedule Page: 402.1 Line No.: 5 Column: b

The Nameplate Rating for Brown CT represents a 47% ownership of unit 5, a 123 MW unit, and 62% ownership of units 6 and 7, which are 177 MW each. The remaining 53% ownership of unit 5, and 38% ownership of units 6 and 7 are owned by Louisville Gas and Electric Company.

Schedule Page: 402.1 Line No.: 5 Column: c

The Nameplate Rating for Paddy's Run 13 CT represents a 47% ownership. Total Nameplate Rating for the unit is 178 MW. The remaining 53% ownership is owned by Louisville Gas and Electric Company.

Schedule Page: 402.1 Line No.: 5 Column: d

The Nameplate Rating for Trimble County CT represents 71% ownership of units 5 and 6 and 63% of units 7, 8, 9 and 10 for Kentucky Utilities Company. The remaining percentages for units 5, 6, 7, 8, 9 and 10 are owned by Louisville Gas and Electric Company. Total Nameplate Ratings for these units are 199 MW per unit.

Schedule Page: 402.1 Line No.: 11 Column: b

Employees at the Brown Plant include those assigned to the steam plant and the Brown CT site and are reflected in the Brown Steam Plant statistics.

Schedule Page: 402.1 Line No.: 11 Column: c

No production/operation employees are directly assigned to Paddy's Run turbines. Employees from the Louisville Gas and Electric Cane Run Plant operate and maintain the Paddy's Run turbines.

Schedule Page: 402.1 Line No.: 11 Column: d

Employees at the Trimble County Plant include those assigned to the steam plant and the Trimble County CT site and are reflected in the Trimble County steam plant statistics.

Schedule Page: 402 Line No.: 36 Column: b2

Oil is used for start up and stabilization of this unit only. No energy is generated from oil burned.

Schedule Page: 402 Line No.: 36 Column: c2

Oil is used for start up and stabilization of this unit only. No energy is generated from oil burned.

Schedule Page: 402 Line No.: 36 Column: d2

Oil is used for start up and stabilization of this unit only. No energy is generated from oil burned.

Schedule Page: 402 Line No.: 36 Column: e2

Oil is used for start up and stabilization of this unit only. No energy is generated from oil burned.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Utilities Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2008/Q4

HYDROELECTRIC GENERATING PLANT STATISTICS (Large Plants)

1. Large plants are hydro plants of 10,000 Kw or more of installed capacity (name plate ratings)
2. If any plant is leased, operated under a license from the Federal Energy Regulatory Commission, or operated as a joint facility, indicate such facts in a footnote. If licensed project, give project number.
3. If net peak demand for 60 minutes is not available, give that which is available specifying period.
4. If a group of employees attends more than one generating plant, report on line 11 the approximate average number of employees assignable to each plant.

Line No.	Item (a)	FERC Licensed Project No. 0 Plant Name: Dix Dam (b)	FERC Licensed Project No. 0 Plant Name: (c)
1	Kind of Plant (Run-of-River or Storage)	Storage	
2	Plant Construction type (Conventional or Outdoor)	Conventional	
3	Year Originally Constructed	1923	
4	Year Last Unit was Installed	1924	
5	Total installed cap (Gen name plate Rating in MW)	28.00	0.00
6	Net Peak Demand on Plant-Megawatts (60 minutes)	18	0
7	Plant Hours Connect to Load	2,993	0
8	Net Plant Capability (in megawatts)		
9	(a) Under Most Favorable Oper Conditions	24	0
10	(b) Under the Most Adverse Oper Conditions	0	0
11	Average Number of Employees	19	0
12	Net Generation, Exclusive of Plant Use - Kwh	50,505,000	0
13	Cost of Plant		
14	Land and Land Rights	879,312	0
15	Structures and Improvements	464,928	0
16	Reservoirs, Dams, and Waterways	0	0
17	Equipment Costs	10,493,686	0
18	Roads, Railroads, and Bridges	0	0
19	Asset Retirement Costs	4,970	0
20	TOTAL cost (Total of 14 thru 19)	11,842,896	0
21	Cost per KW of Installed Capacity (line 20 / 5)	422.9606	0.0000
22	Production Expenses		
23	Operation Supervision and Engineering	7,332	0
24	Water for Power	0	0
25	Hydraulic Expenses	0	0
26	Electric Expenses	0	0
27	Misc Hydraulic Power Generation Expenses	42,056	0
28	Rents	0	0
29	Maintenance Supervision and Engineering	104,880	0
30	Maintenance of Structures	148,534	0
31	Maintenance of Reservoirs, Dams, and Waterways	0	0
32	Maintenance of Electric Plant	76,469	0
33	Maintenance of Misc Hydraulic Plant	5,629	0
34	Total Production Expenses (total 23 thru 33)	384,900	0
35	Expenses per net KWh	0.0076	0.0000

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Utilities Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2008/Q4

HYDROELECTRIC GENERATING PLANT STATISTICS (Large Plants) (Continued)

5. The items under Cost of Plant represent accounts or combinations of accounts prescribed by the Uniform System of Accounts. Production Expenses do not include Purchased Power, System control and Load Dispatching, and Other Expenses classified as "Other Power Supply Expenses."
6. Report as a separate plant any plant equipped with combinations of steam, hydro, internal combustion engine, or gas turbine equipment.

FERC Licensed Project No. 0 Plant Name: (d)	FERC Licensed Project No. 0 Plant Name: (e)	FERC Licensed Project No. 0 Plant Name: (f)	Line No.
			1
			2
			3
			4
0.00	0.00	0.00	5
0	0	0	6
0	0	0	7
			8
0	0	0	9
0	0	0	10
0	0	0	11
0	0	0	12
			13
0	0	0	14
0	0	0	15
0	0	0	16
0	0	0	17
0	0	0	18
0	0	0	19
0	0	0	20
0.0000	0.0000	0.0000	21
			22
0	0	0	23
0	0	0	24
0	0	0	25
0	0	0	26
0	0	0	27
0	0	0	28
0	0	0	29
0	0	0	30
0	0	0	31
0	0	0	32
0	0	0	33
0	0	0	34
0.0000	0.0000	0.0000	35

Name of Respondent Kentucky Utilities Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2008/Q4

TRANSMISSION LINE STATISTICS

1. Report information concerning transmission lines, cost of lines, and expenses for year. List each transmission line having nominal voltage of 132 kilovolts or greater. Report transmission lines below these voltages in group totals only for each voltage.
2. Transmission lines include all lines covered by the definition of transmission system plant as given in the Uniform System of Accounts. Do not report substation costs and expenses on this page.
3. Report data by individual lines for all voltages if so required by a State commission.
4. Exclude from this page any transmission lines for which plant costs are included in Account 121, Nonutility Property.
5. Indicate whether the type of supporting structure reported in column (e) is: (1) single pole wood or steel; (2) H-frame wood, or steel poles; (3) tower; or (4) underground construction If a transmission line has more than one type of supporting structure, indicate the mileage of each type of construction by the use of brackets and extra lines. Minor portions of a transmission line of a different type of construction need not be distinguished from the remainder of the line.
6. Report in columns (f) and (g) the total pole miles of each transmission line. Show in column (f) the pole miles of line on structures the cost of which is reported for the line designated; conversely, show in column (g) the pole miles of line on structures the cost of which is reported for another line. Report pole miles of line on leased or partly owned structures in column (g). In a footnote, explain the basis of such occupancy and state whether expenses with respect to such structures are included in the expenses reported for the line designated.

Line No.	DESIGNATION		VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase)		Type of Supporting Structure	LENGTH (Pole miles) (In the case of underground lines report circuit miles)		Number Of Circuits
	From (a)	To (b)	Operating (c)	Designed (d)	(e)	On Structure of Line Designated (f)	On Structures of Another Line (g)	(h)
1	Pocket	Pineville	500.00	500.00	ST	35.48		
2	Pocket	Phipps Bend	500.00	500.00	ST	21.39		
3								
4	Ghent Plant	Brown North	345.00	345.00	ST	113.87		
5	Ghent Plant	Batesville	345.00	345.00	ST	7.80		
6	Brown Plant	Elmer Smith	345.00	345.00	HF &ST	135.31		
7	Brown North	K.U. Park	345.00	345.00	ST	102.47		2
8								
9	Green River	AEC Buss	161.00	161.00	HF,ST & WP	181.29		
10	Green River	Morganfield	161.00	161.00	HF & WP	55.38		
11	Elihu	Dorchester	161.00	161.00	HF & ST	86.06		
12	Lake Reba	Dorchester	161.00	161.00	HF & ST	99.15		1
13	Pineville	Harlan	161.00	161.00	HF & WP	48.34		
14	Pineville 149	Pineville 192	161.00	161.00	HF	0.12		1
15	East Ky. Power	Taylor County	161.00	161.00	SP	3.97		1
16	Imboden	Harlan	161.00	161.00	HF,SP,WP &	43.82		
17								
18	Ghent Plant	Brown Plant	138.00	138.00	ST	90.47		
19	Brown Plant	Green River	138.00	138.00	HF,SP & ST	169.18		
20	Kenton	Rodburn	138.00	138.00	HF	45.74		1
21	Green River	Brown North	138.00	138.00	HF & ST	166.58		
22	Fawkes	Rodburn	138.00	138.00	HF,ST & WP	64.52		1
23	Clifty Creek	Carrollton	138.00	138.00	HF,SP ,ST &	144.62		
24	Brown Plant	Lake Reba	138.00	138.00	HF	28.60		1
25	Brown Plant	Haefling	138.00	138.00	HF,SP,ST &	29.32		
26	Ghent Plant	Kenton Station	138.00	138.00	HF & WF	72.78		1
27	Ghent Plant	Adams	138.00	138.00	HF,SP & ST	56.77		
28	Hardin County	Rogersville	138.00	138.00	HF	10.24		1
29	Virginia City	Clinch River (AEP Int. Pt)	138.00	138.00	HF	7.89		1
30	69KV Lines		69.00	69.00	Various	2,218.58		
31								
32								
33								
34	Exp Applicable to All Lines							
35								
36					TOTAL	4,039.74		11

Name of Respondent Kentucky Utilities Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2008/Q4

TRANSMISSION LINE STATISTICS (Continued)

7. Do not report the same transmission line structure twice. Report Lower voltage Lines and higher voltage lines as one line. Designate in a footnote if you do not include Lower voltage lines with higher voltage lines. If two or more transmission line structures support lines of the same voltage, report the pole miles of the primary structure in column (f) and the pole miles of the other line(s) in column (g)
8. Designate any transmission line or portion thereof for which the respondent is not the sole owner. If such property is leased from another company, give name of lessor, date and terms of Lease, and amount of rent for year. For any transmission line other than a leased line, or portion thereof, for which the respondent is not the sole owner but which the respondent operates or shares in the operation of, furnish a succinct statement explaining the arrangement and giving particulars (details) of such matters as percent ownership by respondent in the line, name of co-owner, basis of sharing expenses of the Line, and how the expenses borne by the respondent are accounted for, and accounts affected. Specify whether lessor, co-owner, or other party is an associated company.
9. Designate any transmission line leased to another company and give name of Lessee, date and terms of lease, annual rent for year, and how determined. Specify whether lessee is an associated company.
10. Base the plant cost figures called for in columns (j) to (l) on the book cost at end of year.

Size of Conductor and Material (i)	COST OF LINE (Include in Column (j) Land, Land rights, and clearing right-of-way) Land (j)	Construction and Other Costs (k)	Total Cost (l)	EXPENSES, EXCEPT DEPRECIATION AND TAXES Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)	Line No.
954mcm	1,385,561	15,452,581	16,838,142					1
954mcm	280,371	7,945,173	8,225,544					2
								3
795mcm	2,495,681	16,982,353	19,478,034					4
954mcm	437,159	4,810,707	5,247,866					5
954mcm	1,615,764	17,505,359	19,121,123					6
954mcm	1,111,580	21,486,959	22,598,539					7
								8
556mcm	1,284,447	10,991,810	12,276,257					9
556mcm	268,660	2,132,034	2,400,694					10
556mcm	270,147	3,983,801	4,253,948					11
556mcm	559,988	4,024,255	4,584,243					12
795mcm	300,849	6,106,847	6,407,696					13
954mcm		14,306	14,306					14
556mcm	261,988	307,188	569,176					15
795mcm	84,143	4,521,262	4,605,405					16
								17
954mcm	419,701	5,830,853	6,250,554					18
556mcm	381,153	6,805,683	7,186,836					19
397mcm	98,119	1,278,207	1,376,326					20
795mcm	732,412	7,728,047	8,460,459					21
556mcm	579,168	2,095,867	2,675,035					22
795mcm	824,816	9,874,355	10,699,171					23
556mcm	80,240	942,266	1,022,506					24
795mcm	191,989	4,322,655	4,514,644					25
795mcm	446,858	4,002,028	4,448,886					26
795mcm	245,501	5,164,163	5,409,664					27
795mcm	245,093	919,472	1,164,565					28
795mcm		5,158,100	5,158,100					29
Various	8,202,312	126,057,783	134,260,095					30
								31
								32
								33
								34
				424,984	3,143,960	99,500	3,668,444	35
	22,803,700	296,444,114	319,247,814	424,984	3,143,960	99,500	3,668,444	36

BLANK

FOOTNOTE DATA

Schedule Page: 422 Line No.: 1 Column: h
Contains both single and double circuitry.

Schedule Page: 422 Line No.: 2 Column: h
Contains both single and double circuitry.

Schedule Page: 422 Line No.: 4 Column: h
Contains both single and double circuitry.

Schedule Page: 422 Line No.: 5 Column: h
Contains both single and double circuitry.

Schedule Page: 422 Line No.: 6 Column: h
Contains both single and double circuitry.

Schedule Page: 422 Line No.: 9 Column: h
Contains both single and double circuitry.

Schedule Page: 422 Line No.: 10 Column: h
Contains both single and double circuitry.

Schedule Page: 422 Line No.: 11 Column: h
Contains both single and double circuitry.

Schedule Page: 422 Line No.: 13 Column: h
Contains both single and double circuitry.

Schedule Page: 422 Line No.: 16 Column: h
Contains both single and double circuitry.

Schedule Page: 422 Line No.: 18 Column: h
Contains both single and double circuitry.

Schedule Page: 422 Line No.: 19 Column: h
Contains both single and double circuitry.

Schedule Page: 422 Line No.: 21 Column: h
Contains both single and double circuitry.

Schedule Page: 422 Line No.: 23 Column: h
Contains both single and double circuitry.

Schedule Page: 422 Line No.: 25 Column: h
Contains both single and double circuitry.

Schedule Page: 422 Line No.: 27 Column: h
Contains both single and double circuitry.

Schedule Page: 422 Line No.: 30 Column: h
Contains both single and double circuitry.

Name of Respondent Kentucky Utilities Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2008/Q4

TRANSMISSION LINES ADDED DURING YEAR

1. Report below the information called for concerning Transmission lines added or altered during the year. It is not necessary to report minor revisions of lines.
2. Provide separate subheadings for overhead and under- ground construction and show each transmission line separately. If actual costs of competed construction are not readily available for reporting columns (l) to (o), it is permissible to report in these columns the

Line No.	LINE DESIGNATION From (a)	LINE DESIGNATION To (b)	Line Length In Miles (c)	SUPPORTING STRUCTURE Type (d)	SUPPORTING STRUCTURE Average Number per Miles (e)	CIRCUITS PER STRUCTURE Present (f)	CIRCUITS PER STRUCTURE Ultimate (g)
1	Virginia City	Clinch River (AEP Int. Pt)	7.89	HF		1	
2							
3							
4							
5							
6							
7							
8							
9							
10							
11							
12							
13							
14							
15							
16							
17							
18							
19							
20							
21							
22							
23							
24							
25							
26							
27							
28							
29							
30							
31							
32							
33							
34							
35							
36							
37							
38							
39							
40							
41							
42							
43							
44	TOTAL		7.89			1	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Utilities Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2008/Q4

TRANSMISSION LINES ADDED DURING YEAR (Continued)

costs. Designate, however, if estimated amounts are reported. Include costs of Clearing Land and Rights-of-Way, and Roads and Trails, in column (l) with appropriate footnote, and costs of Underground Conduit in column (m).

3. If design voltage differs from operating voltage, indicate such fact by footnote; also where line is other than 60 cycle, 3 phase, indicate such other characteristic.

CONDUCTORS			Voltage	LINE COST					Line
Size (h)	Specification (i)	Configuration and Spacing (j)	KV (Operating) (k)	Land and Land Rights (l)	Poles, Towers and Fixtures (m)	Conductors and Devices (n)	Asset Retire. Costs (o)	Total (p)	No.
795mcm			138,000		3,868,575	1,289,525		5,158,100	1
									2
									3
									4
									5
									6
									7
									8
									9
									10
									11
									12
									13
									14
									15
									16
									17
									18
									19
									20
									21
									22
									23
									24
									25
									26
									27
									28
									29
									30
									31
									32
									33
									34
									35
									36
									37
									38
									39
									40
									41
									42
									43
					3,868,575	1,289,525		5,158,100	44

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Utilities Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2008/Q4

SUBSTATIONS

1. Report below the information called for concerning substations of the respondent as of the end of the year.
2. Substations which serve only one industrial or street railway customer should not be listed below.
3. Substations with capacities of Less than 10 MVa except those serving customers with energy for resale, may be grouped according to functional character, but the number of such substations must be shown.
4. Indicate in column (b) the functional character of each substation, designating whether transmission or distribution and whether attended or unattended. At the end of the page, summarize according to function the capacities reported for the individual stations in column (f).

Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	Adams - Georgetown	Transmission *	138.00	69.00	13.20
2	Alcade - Somerset	Transmission *	345.00	161.00	13.20
3	American Ave. - Lexington	Transmission *	138.00	69.00	13.20
4	Arnold - Cumberland	Transmission *	161.00	69.00	13.20
5	Artemus - Pineville	Transmission *	161.00	69.00	13.20
6	Bardstown- Campellsville	Transmission *	138.00	69.00	13.20
7	Beattyville - Richmond	Transmission *	161.00	69.00	13.20
8	Bimble	Transmission*	69.00		
9	Blackwell	Transmission*	138.00		
10	Bonds Mill	Transmission*	69.00		
11	Bonnieville - Horse Cave	Transmission *	138.00	69.00	13.20
12	Boonesboro North - Winchester	Transmission *	138.00	69.00	13.20
13	Boyle County	Transmission*	69.00		
14	Broadhead SW	Transmission*	69.00		
15	Brown CT 7 - Harrodsburg	Transmission (G)	145.00	18.00	
16	Brown CT 6 - Harrodsburg	Transmission (G)	145.00	13.80	
17	Brown North - Harrodsburg	Transmission *	345.00	138.00	13.20
18	Brown North - Harrodsburg	Transmission *	144.00	24.00	
19	Brown Plant - Harrodsburg	Transmission (G)	138.00	13.20	
20	Brown Plant - Harrodsburg	Transmission (G)	138.00	17.10	
21	Carntown - Augusta	Transmission *	138.00	69.00	13.20
22	Carrollton - Carrollton	Transmission *	138.00	69.00	13.20
23	Cary SW	Transmission*	69.00		
24	Clark County - Winchester	Transmission *	138.00	69.00	13.20
25	Clinton	Transmission*	69.00		
26	Corydon - Henderson	Transmission *	161.00	69.00	13.20
27	Crittendon County - Marion	Transmission *	161.00	69.00	13.20
28	Cynthiana SW	Transmission*	69.00		
29	Danville North - Danville	Transmission *	138.00	69.00	13.20
30	Daviess County	Transmission*	345.00		
31	Delvinta	Transmission*	161.00		
32	Dix Dam Plant - Harrodsburg	Transmission (G)	69.00	13.20	
33	Dow Corning West	Transmission*	138.00		
34	Dorchester - Norton	Transmission *	161.00	69.00	13.20
35	Earlington North - Earlington	Transmission *	161.00	69.00	13.20
36	East Frankfort - Frankfort	Transmission *	138.00	69.00	13.20
37	Elihu - Somerset	Transmission *	161.00	69.00	13.20
38	Elizabethtown - Elizabethtown	Transmission *	138.00	69.00	13.20
39	Eminence	Transmission*	69.00		
40	Evarts	Transmission*	69.00		

Name of Respondent Kentucky Utilities Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2008/Q4

SUBSTATIONS (Continued)

5. Show in columns (I), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.
6. Designate substations or major items of equipment leased from others, jointly owned with others, or operated otherwise than by reason of sole ownership by the respondent. For any substation or equipment operated under lease, give name of lessor, date and period of lease, and annual rent. For any substation or equipment operated other than by reason of sole ownership or lease, give name of co-owner or other party, explain basis of sharing expenses or other accounting between the parties, and state amounts and accounts affected in respondent's books of account. Specify in each case whether lessor, co-owner, or other party is an associated company.

Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	Line No.
94	1		NONE			1
448	1		NONE			2
150	1		NONE			3
56	1		NONE			4
56	1		NONE			5
94	1		NONE			6
56	1		NONE			7
			NONE			8
			NONE			9
			NONE			10
34	1		NONE			11
150	1		NONE			12
			NONE			13
			NONE			14
380	2		NONE			15
728	5		NONE			16
448	1		NONE			17
504	1		NONE			18
120	1		NONE			19
185	1		NONE			20
50	1		NONE			21
187	2		NONE			22
			NONE			23
93	1		NONE			24
			NONE			25
112	1		NONE			26
112	1		NONE			27
			NONE			28
112	1		NONE			29
			NONE			30
			NONE			31
31	3		NONE			32
			NONE			33
187	2		NONE			34
224	1		NONE			35
224	2		NONE			36
187	2		NONE			37
150	1		NONE			38
			NONE			39
			NONE			40

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Utilities Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2008/Q4

SUBSTATIONS

1. Report below the information called for concerning substations of the respondent as of the end of the year.
2. Substations which serve only one industrial or street railway customer should not be listed below.
3. Substations with capacities of Less than 10 MVa except those serving customers with energy for resale, may be grouped according to functional character, but the number of such substations must be shown.
4. Indicate in column (b) the functional character of each substation, designating whether transmission or distribution and whether attended or unattended. At the end of the page, summarize according to function the capacities reported for the individual stations in column (f).

Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	Farley - Corbin	Transmission *	161.00	69.00	13.20
2	Farmers - Morehead	Transmission *	80.00	40.00	13.20
3	Fawkes - Richmond	Transmission *	138.00	69.00	13.20
4	Finchville	Transmission*	69.00		
5	Ghent Plant - Carrollton	Transmission *	345.00	138.00	
6	Ghent Plant - Carrollton	Transmission *	345.00	138.00	25.00
7	Ghent Plant - Carrollton	Transmission (G)	144.00	18.00	
8	Ghent Plant - Carrollton	Transmission (G)	345.00	21.00	
9	Ghent Plant - Carrollton	Transmission (G)	362.00	22.00	
10	Goddard	Transmission*	138.00		
11	Gorge SW	Transmission*	69.00		
12	Grahamville - Barlow	Transmission *	161.00	69.00	13.20
13	Green River Plant - Greenville	Transmission (G)	138.00	13.20	
14	Green River Plant - Greenville	Transmission	138.00	69.00	13.20
15	Green River Plant - Greenville	Transmission	154.00	138.00	13.20
16	Green River Plant - Greenville	Transmission	161.00	138.00	13.20
17	Green River Steel - Greenville	Transmission *	138.00	69.00	13.20
18	Haefling - Lexington	Transmission (G)	69.00	13.20	
19	Haefling - Lexington	Transmission *	138.00	69.00	13.20
20	Hardin County - Elizabethtown	Transmission *	345.00	138.00	13.20
21	Hardin County - Elizabethtown	Transmission *	138.00	69.00	13.20
22	Hardinsburg - Hardinsburg	Transmission*	138.00		
23	Harlan "Y" - Harlan	Transmission *	161.00	69.00	13.20
24	Higby Mill - Lexington	Transmission *	138.00	69.00	13.20
25	Hillside	Transmission*	69.00		
26	Howards Branch	Transmission*	161.00		
27	Imboden - Big Stone Gap	Transmission *	161.00	69.00	13.20
28	Indian Hill	Transmission*	69.00		
29	Kenton - Maysville	Transmission *	132.00	69.00	13.20
30	Kenton - Maysville	Transmission *	138.00	69.00	13.20
31	KU Park - Pineville	Transmission*	69.00		
32	Lake Reba - Richmond	Transmission *	138.00	69.00	13.20
33	Lake Reba Tap - Richmond	Transmission *	161.00	138.00	6.60
34	Lancaster	Transmission*	69.00		
35	Lansdowne - Lexington	Transmission *	138.00	69.00	13.20
36	Lebanon - Lebanon	Transmission *	80.00	40.00	13.20
37	Leitchfield - Leitchfield	Transmission *	138.00	69.00	13.20
38	Lexington Plant - Lexington	Transmission*	69.00		
39	Livingston County	Transmission*	161.00		
40	London - London	Transmission*	69.00		

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Utilities Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2008/Q4

SUBSTATIONS (Continued)

5. Show in columns (I), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.
6. Designate substations or major items of equipment leased from others, jointly owned with others, or operated otherwise than by reason of sole ownership by the respondent. For any substation or equipment operated under lease, give name of lessor, date and period of lease, and annual rent. For any substation or equipment operated other than by reason of sole ownership or lease, give name of co-owner or other party, explain basis of sharing expenses or other accounting between the parties, and state amounts and accounts affected in respondent's books of account. Specify in each case whether lessor, co-owner, or other party is an associated company.

Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT: Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	Line No.
149	1		NONE			1
40	3		NONE			2
299	2		NONE			3
			NONE			4
450	1	1	NONE			5
448	1		NONE			6
616	1	1	NONE			7
1210	2		NONE			8
605	1		NONE			9
			NONE			10
			NONE			11
93	1		NONE			12
214	2	3	NONE			13
261	2		NONE			14
200	2		NONE			15
112	1		NONE			16
93	1		NONE			17
59	1		NONE			18
149	1		NONE			19
448	1		NONE			20
149	1		NONE			21
			NONE			22
94	1		NONE			23
224	2		NONE			24
			NONE			25
			NONE			26
149	1		NONE			27
			NONE			28
33	1	1	NONE			29
112	1		NONE			30
		6	NONE			31
149	1		NONE			32
200	1		NONE			33
			NONE			34
112	1		NONE			35
100	6		NONE			36
93	1		NONE			37
			NONE			38
			NONE			39
			NONE			40

Name of Respondent Kentucky Utilities Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2008/Q4

SUBSTATIONS

1. Report below the information called for concerning substations of the respondent as of the end of the year.
2. Substations which serve only one industrial or street railway customer should not be listed below.
3. Substations with capacities of Less than 10 MVa except those serving customers with energy for resale, may be grouped according to functional character, but the number of such substations must be shown.
4. Indicate in column (b) the functional character of each substation, designating whether transmission or distribution and whether attended or unattended. At the end of the page, summarize according to function the capacities reported for the individual stations in column (f).

Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	Loudon Ave - Lexington	Transmission *	138.00	69.00	13.20
2	Lynch - Harlan	Transmission*	69.00		
3	Marion	Transmission*	69.00		
4	Meldrum SW	Transmission*	69.00		
5	Middlesboro - Middlesboro	Transmission*	69.00		
6	Millersburg - Millersburg	Transmission*	69.00		
7	Morganfield - Morganfield	Transmission *	161.00	69.00	13.20
8	N.A.S.	Transmission*	345.00	138.00	
9	Nebo - Nebo	Transmission*	69.00		
10	North London -London	Transmission*	69.00		
11	Ohio County - Beaver Dam	Transmission *	138.00	69.00	13.20
12	Paris	Transmission*	138.00	69.00	13.20
13	Pineville - Pineville	Transmission *	345.00	161.00	13.20
14	Pineville - Pineville	Transmission *	500.00	345.00	34.50
15	Pineville - Pineville	Transmission *	161.00	69.00	13.20
16	Pineville SW -Pineville	Transmission*	161.00		
17	Pisgah - Lexington	Transmission *	138.00	69.00	13.20
18	Pittsburg - London	Transmission *	161.00	69.00	13.20
19	Pocket - Pennington Gap	Transmission *	161.00	69.00	13.20
20	Pocket North - Pennington Gap	Transmission *	500.00	161.00	
21	Princeton - Princeton	Transmission*	69.00		
22	Richmond - Richmond	Transmission*	69.00		
23	River Queen - Muhlenberg	Transmission *	161.00	69.00	13.20
24	Rocky Branch	Transmission*	69.00		
25	Rodburn - Morehead	Transmission *	138.00	69.00	13.20
26	Rogersvile - Radcliff	Transmission *	138.00	69.00	13.20
27	Scott County	Transmission *	138.00	69.00	13.20
28	Shelbyville - Shelbyville	Transmission*	69.00		
29	Simmons	Transmission*	69.00		
30	Somerset N - Somerset	Transmission*	69.00		
31	South Paducah	Transmission *	161.00	69.00	13.20
32	Spears SW	Transmission*	69.00		
33	Spencer Road - Mt. Sterling	Transmission *	138.00	69.00	13.20
34	Sweet Hollow	Transmission*	69.00		
35	Taylor County - Campellsville	Transmission *	161.00	69.00	13.20
36	Tyrone - Versailles	Transmission (G)	40.00	13.20	
37	Tyrone - Versailles	Transmission (G)	69.00	13.20	
38	Tyrone - Versailles	Transmission *	138.00	69.00	13.20
39	UK Medical Center - Lexington	Transmission*	69.00		
40	Virginia City - Norton	Transmission*	138.00	69.00	13.20

Name of Respondent Kentucky Utilities Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2008/Q4

SUBSTATIONS (Continued)

5. Show in columns (I), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.
6. Designate substations or major items of equipment leased from others, jointly owned with others, or operated otherwise than by reason of sole ownership by the respondent. For any substation or equipment operated under lease, give name of lessor, date and period of lease, and annual rent. For any substation or equipment operated other than by reason of sole ownership or lease, give name of co-owner or other party, explain basis of sharing expenses or other accounting between the parties, and state amounts and accounts affected in respondent's books of account. Specify in each case whether lessor, co-owner, or other party is an associated company.

Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	Line No.
262	2		NONE			1
			NONE			2
			NONE			3
			NONE			4
			NONE			5
			NONE			6
112	1		NONE			7
450	1		NONE			8
			NONE			9
			NONE			10
93	1	3	NONE			11
150	1		NONE			12
560	1		NONE			13
504	1		NONE			14
243	2		NONE			15
			NONE			16
112	1		NONE			17
112	1		NONE			18
187	1		NONE			19
448	1		NONE			20
			NONE			21
			NONE			22
56	1		NONE			23
			NONE			24
61	1		NONE			25
93	1		NONE			26
93	1		NONE			27
			NONE			28
			NONE			29
			NONE			30
50	1		NONE			31
			NONE			32
89	2		NONE			33
			NONE			34
90	1		NONE			35
38	3	1	NONE			36
83	1	1	NONE			37
112	1	1	NONE			38
			NONE			39
120	1		NONE			40

Name of Respondent Kentucky Utilities Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2008/Q4

SUBSTATIONS

1. Report below the information called for concerning substations of the respondent as of the end of the year.
2. Substations which serve only one industrial or street railway customer should not be listed below.
3. Substations with capacities of Less than 10 MVa except those serving customers with energy for resale, may be grouped according to functional character, but the number of such substations must be shown.
4. Indicate in column (b) the functional character of each substation, designating whether transmission or distribution and whether attended or unattended. At the end of the page, summarize according to function the capacities reported for the individual stations in column (f).

Line No.	Name and Location of Substation	Character of Substation	VOLTAGE (In MVa)		
			Primary	Secondary	Tertiary
	(a)	(b)	(c)	(d)	(e)
1	Walker - Earlington	Transmission *	161.00	69.00	13.20
2	West Cliff - Harrodsburg	Transmission *	138.00	69.00	13.20
3	West Frankfort - Shelbyville	Transmission *	345.00	138.00	13.20
4	West Frankfort - Shelbyville	Transmission *	138.00	69.00	13.20
5	West Irvine - Irvine	Transmission *	161.00	69.00	13.20
6	West Lexington - Lexington	Transmission *	345.00	138.00	13.20
7	Wheatcroft	Transmission*	69.00		
8	Wickliffe - Barlow	Transmission *	161.00	69.00	13.20
9	Williamsburg SW	Transmission*	69.00		
10	Winchester City	Transmission*	69.00		
11	Wofford	Transmission*	69.00		
12	Total Transmission		19009.00	6365.10	937.30
13					
14	A.O. Smith - Mt. Sterling	Distribution *	69.00	12.47	
15	Adams 12KV	Distribution *	69.00	34.50	
16	Aisin 12KV	Distribution *	69.00	12.47	
17	Alexander - Versailles	Distribution *	69.00	12.47	
18	American Ave. - Lexington	Distribution *	69.00	4.16	
19	Andover - Norton	Distribution*	69.00	34.50	
20	Ashland Ave. - Lexington	Distribution *	69.00	4.16	
21	Ashland Pipe - Lexington	Distribution *	69.00	12.47	
22	Augusta 12KV	Distribution *	69.00	12.47	
23	Bardstown City 12KV	Distribution *	69.00	12.47	
24	Bardstown Ind. 12KV	Distribution *	69.00	12.47	
25	Beaver Dam - Beaver Dam	Distribution *	69.00	12.47	
26	Beaver Dam North - Beaver Dam	Distribution *	69.00	12.47	
27	Belt Line - Lexington	Distribution *	69.00	12.47	
28	Bevier - Earlington	Distribution*	69.00	34.50	
29	Big Stone Gap - Big Stone Gap	Distribution *	69.00	12.47	
30	Bond - Coeburn	Distribution *	69.00	12.47	
31	Boone Ave. - Winchester	Distribution *	69.00	12.47	
32	Borg Warner - Earlington	Distribution *	69.00	12.47	
33	Bryant Road - Lexington	Distribution *	69.00	12.47	
34	Buchanan - Lexington	Distribution *	69.00	4.16	
35	Buena Vista 12KV	Distribution *	69.00	12.47	
36	Burnside - Somerset	Distribution *	69.00	12.47	
37	Camargo - Mt. Sterling	Distribution *	69.00	12.47	
38	Camp Breckinridge	Distribution*	69.00	12.47	
39	Campellsville 1 - Campellsville	Distribution *	69.00	12.47	
40	Campellsville 2 - Campellsville	Distribution*	69.00	12.47	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Utilities Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2008/Q4

SUBSTATIONS (Continued)

5. Show in columns (I), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.
6. Designate substations or major items of equipment leased from others, jointly owned with others, or operated otherwise than by reason of sole ownership by the respondent. For any substation or equipment operated under lease, give name of lessor, date and period of lease, and annual rent. For any substation or equipment operated other than by reason of sole ownership or lease, give name of co-owner or other party, explain basis of sharing expenses or other accounting between the parties, and state amounts and accounts affected in respondent's books of account. Specify in each case whether lessor, co-owner, or other party is an associated company.

Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	Line No.
112	1		NONE			1
392	3		NONE			2
448	1		NONE			3
			NONE			4
56	1		NONE			5
448	1		NONE			6
			NONE			7
93	1		NONE			8
			NONE			9
			NONE			10
			NONE			11
17700	115	18				12
						13
14	1		NONE			14
34	2		NONE			15
14	1		NONE			16
22	1		NONE			17
14	1		NONE			18
37	1		NONE			19
28	2		NONE			20
20	2		NONE			21
14	1		NONE			22
23	1		NONE			23
45	2		NONE			24
14	1		NONE			25
14	1		NONE			26
23	1		NONE			27
13	1		NONE			28
42	3		NONE			29
67	3		NONE			30
23	1		NONE			31
23	1		NONE			32
67	3		NONE			33
14	1		NONE			34
14	1		NONE			35
14	1		NONE			36
28	2		NONE			37
14	1		NONE			38
45	2		NONE			39
23	1		NONE			40

Name of Respondent Kentucky Utilities Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2008/Q4

SUBSTATIONS

1. Report below the information called for concerning substations of the respondent as of the end of the year.
2. Substations which serve only one industrial or street railway customer should not be listed below.
3. Substations with capacities of Less than 10 MVa except those serving customers with energy for resale, may be grouped according to functional character, but the number of such substations must be shown.
4. Indicate in column (b) the functional character of each substation, designating whether transmission or distribution and whether attended or unattended. At the end of the page, summarize according to function the capacities reported for the individual stations in column (f).

Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	Carntown - Augusta	Distribution *	69.00	12.47	
2	Caron - London	Distribution *	69.00	12.47	
3	Carrollton - Carrollton	Distribution *	69.00	12.47	
4	Cawood - Harlan	Distribution *	69.00	12.47	
5	Clay Mills - Lexington	Distribution *	138.00	12.47	
6	Clinch Valley - Norton	Distribution *	69.00	12.47	
7	Columbia - Columbia	Distribution *	69.00	12.47	
8	Columbia South - Columbia	Distribution *	69.00	12.47	
9	Corbin East - Corbin	Distribution *	69.00	12.47	
10	Corning 12KV	Distribution *	69.00	12.47	
11	Corporate Drive 2 - 12KV	Distribution *	69.00	12.47	
12	Cynthiana 12KV	Distribution *	69.00	12.47	
13	Cynthiana South 12KV	Distribution *	67.00	12.47	
14	Danville 1 - Danville	Distribution *	69.00	12.47	
15	Danville East - Danville	Distribution *	69.00	12.47	
16	Danville Ind. - Danville	Distribution *	69.00	12.47	
17	Danville North - Danville	Distribution *	69.00	12.47	
18	Danville West - Danville	Distribution *	69.00	12.47	
19	Dark Hollow - Richmond	Distribution *	69.00	12.47	
20	Dawson Ind. - Earlington	Distribution *	69.00	4.16	
21	Days Branch 12KV	Distribution *	69.00	12.47	
22	Dayton - Walther - Carrollton	Distribution *	138.00	12.47	
23	Delaplain - Georgetown	Distribution *	69.00	13.80	
24	Denham Street - Somerset	Distribution *	69.00	12.47	
25	Detroit Harvester - Paris	Distribution *	69.00	12.47	
26	Donerail - Lexington	Distribution *	69.00	12.47	
27	Dorchester - Norton	Distribution *	69.00	22.00	
28	Dow Corning - Carrollton	Distribution *	69.00	12.47	
29	Dozier Heights 12KV	Distribution *	69.00	12.47	
30	Earlington - Earlington	Distribution *	69.00	34.50	
31	East Bernstadt - London	Distribution *	69.00	12.47	
32	East Stone - Big Stone Gap	Distribution *	69.00	12.47	
33	Eastland - Lexington	Distribution *	69.00	12.47	
34	Elizabethtown Industrial - Elizabethtown	Distribution *	69.00	12.47	
35	Eminence - Shelbyville	Distribution *	69.00	12.47	
36	Esserville - Norton	Distribution *	69.00	12.47	
37	Etown #2 - Elizabethtown	Distribution *	69.00	12.47	
38	Etown #3 - Elizabethtown	Distribution*	69.00	12.47	
39	Etown #4 - Elizabethtown	Distribution *	69.00	12.47	
40	Etown #5 East - Elizabethtown	Distribution *	69.00	12.47	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Utilities Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2008/Q4

SUBSTATIONS (Continued)

5. Show in columns (I), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.
6. Designate substations or major items of equipment leased from others, jointly owned with others, or operated otherwise than by reason of sole ownership by the respondent. For any substation or equipment operated under lease, give name of lessor, date and period of lease, and annual rent. For any substation or equipment operated other than by reason of sole ownership or lease, give name of co-owner or other party, explain basis of sharing expenses or other accounting between the parties, and state amounts and accounts affected in respondent's books of account. Specify in each case whether lessor, co-owner, or other party is an associated company.

Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	Line No.
14	1		NONE			1
23	1		NONE			2
14	1		NONE			3
14	1		NONE			4
37	1		NONE			5
23	1		NONE			6
14	1		NONE			7
14	1		NONE			8
37	2		NONE			9
34	5		NONE			10
30	2		NONE			11
20	2		NONE			12
14	1		NONE			13
23	1		NONE			14
23	1		NONE			15
45	2		NONE			16
14	1		NONE			17
23	1		NONE			18
14	1		NONE			19
14	1		NONE			20
14	1		NONE			21
14	1		NONE			22
37	2		NONE			23
14	1		NONE			24
23	1		NONE			25
14	1		NONE			26
56	3		NONE			27
14	1		NONE			28
14	1		NONE			29
34	2		NONE			30
14	1		NONE			31
25	2		NONE			32
23	1		NONE			33
23	1		NONE			34
14	1		NONE			35
23	1		NONE			36
45	2		NONE			37
33	2		NONE			38
23	1		NONE			39
14	1		NONE			40

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Utilities Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2008/Q4

SUBSTATIONS

1. Report below the information called for concerning substations of the respondent as of the end of the year.
2. Substations which serve only one industrial or street railway customer should not be listed below.
3. Substations with capacities of Less than 10 MVa except those serving customers with energy for resale, may be grouped according to functional character, but the number of such substations must be shown.
4. Indicate in column (b) the functional character of each substation, designating whether transmission or distribution and whether attended or unattended. At the end of the page, summarize according to function the capacities reported for the individual stations in column (f).

Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	Etown West - Elizabethtown	Distribution *	69.00	12.47	
2	Ewington - Mt. Sterling	Distribution *	69.00	12.47	
3	Ferguson South - Somerset	Distribution *	69.00	12.47	
4	Florida Tile - Lawrenceburg	Distribution *	69.00	12.47	
5	FMC - Lexington	Distribution *	69.00	12.47	
6	Forks of Elkhorn - Georgetown	Distribution *	34.50	12.47	
7	Frankfort - Frankfort	Distribution*	69.00	34.50	
8	GE Lamp Works - Lexington	Distribution *	69.00	4.16	
9	Georgetown - Georgetown	Distribution *	69.00	12.47	
10	Ghent Scrubbers 12KV	Distribution*	138.00	13.20	
11	Green River Steel 2 12KV	Distribution *	69.00	12.47	
12	Green River 34KV	Distribution*	69.00	34.50	
13	Greensburg - Campellsville	Distribution *	69.00	12.47	
14	Greenville 12KV - Muhlenburg	Distribution *	69.00	12.47	
15	Greenville North - Muhlenburg	Distribution *	69.00	12.47	
16	Haefling - Lexington	Distribution *	138.00	12.47	
17	Haley - Lexington	Distribution *	69.00	12.47	
18	Hamblin - Pennington Gap	Distribution *	69.00	12.47	
19	Hanson - Earlington	Distribution *	69.00	12.47	
20	Hardesty - Earlington	Distribution*	69.00	34.50	
21	Harlan - Harlan	Distribution *	69.00	12.47	
22	Harlan Wye - Harlan	Distribution *	69.00	12.47	
23	Harrodsburg #2 - Harrodsburg	Distribution *	69.00	12.47	
24	Harrodsburg #3 - Harrodsburg	Distribution *	69.00	12.47	
25	Harrodsburg North 12KV	Distribution *	69.00	12.47	
26	Higby Mill 12KV - Lexington	Distribution *	138.00	12.47	
27	Highsplint - Harlan	Distribution *	69.00	12.47	
28	Hodgenville 12KV	Distribution *	69.00	12.47	
29	Hoover 12KV - Georgetown	Distribution *	69.00	12.47	
30	Hopewell - Corbin	Distribution *	69.00	12.47	
31	Horse Cave 12KV	Distribution *	69.00	12.47	
32	Horse Cave Industrial - Horse Cave	Distribution *	69.00	12.47	
33	Hughes Lane - Lexington	Distribution *	69.00	12.47	
34	IBM - Lexington	Distribution *	69.00	12.47	
35	IBM North 12KV	Distribution *	138.00	12.47	
36	Imboden - Norton	Distribution*	69.00	34.50	
37	Irvine - Richmond	Distribution *	69.00	12.47	
38	Joyland - Lexington	Distribution *	69.00	12.47	
39	Kawneer - Cynthiana	Distribution *	69.00	12.47	
40	Kenton - Maysville	Distribution *	69.00	12.47	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Utilities Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2008/Q4

SUBSTATIONS (Continued)

5. Show in columns (I), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.
6. Designate substations or major items of equipment leased from others, jointly owned with others, or operated otherwise than by reason of sole ownership by the respondent. For any substation or equipment operated under lease, give name of lessor, date and period of lease, and annual rent. For any substation or equipment operated other than by reason of sole ownership or lease, give name of co-owner or other party, explain basis of sharing expenses or other accounting between the parties, and state amounts and accounts affected in respondent's books of account. Specify in each case whether lessor, co-owner, or other party is an associated company.

Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	Line No.
23	1		NONE			1
28	2		NONE			2
14	1		NONE			3
14	1		NONE			4
23	1		NONE			5
14	1		NONE			6
20	1		NONE			7
14	1		NONE			8
14	1		NONE			9
28	1		NONE			10
14	1		NONE			11
17	1		NONE			12
14	1		NONE			13
14	1		NONE			14
14	1		NONE			15
39	1		NONE			16
14	1		NONE			17
14	1		NONE			18
14	1		NONE			19
13	1		NONE			20
14	1		NONE			21
14	1		NONE			22
14	1		NONE			23
14	1		NONE			24
14	1		NONE			25
60	2		NONE			26
14	1		NONE			27
14	1		NONE			28
14	1		NONE			29
28	2		NONE			30
28	2		NONE			31
45	2		NONE			32
14	1		NONE			33
75	2		NONE			34
34	1		NONE			35
37	1		NONE			36
14	1		NONE			37
37	2		NONE			38
14	1		NONE			39
28	2		NONE			40

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Utilities Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2008/Q4

SUBSTATIONS

1. Report below the information called for concerning substations of the respondent as of the end of the year.
2. Substations which serve only one industrial or street railway customer should not be listed below.
3. Substations with capacities of Less than 10 MVa except those serving customers with energy for resale, may be grouped according to functional character, but the number of such substations must be shown.
4. Indicate in column (b) the functional character of each substation, designating whether transmission or distribution and whether attended or unattended. At the end of the page, summarize according to function the capacities reported for the individual stations in column (f).

Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	Kentucky River 4KV	Distribution *	69.00	4.16	
2	LaGrange East	Distribution *	69.00	12.47	
3	LaGrange - Penal - LaGrange	Distribution *	69.00	12.47	
4	Lakeshore - Lexington	Distribution *	69.00	12.47	
5	Lancaster - Danville	Distribution*	69.00	4.16	
6	Lansdowne - Lexington	Distribution *	69.00	12.47	
7	Lawrenceburg - Lawrenceburg	Distribution *	69.00	12.47	
8	Lebanon - Lebanon	Distribution*	69.00	12.47	
9	Lebanon East	Distribution*	69.00	12.47	
10	Lebanon South 12KV - Lebanon	Distribution *	69.00	12.47	
11	Lebanon Junction 12KV	Distribution *	69.00	12.47	
12	Lebanon West 12KV	Distribution*	138.00	12.47	
13	Leitchfield 12KV - Leitchfield	Distribution *	69.00	12.47	
14	Leitchfield East - Leitchfield	Distribution *	69.00	12.47	
15	Lemons Mill - Georgetown	Distribution *	69.00	12.47	
16	Lexington Water Comapany	Distribution *	69.00	12.47	
17	Lexington 4KV - Lexington	Distribution *	69.00	4.16	
18	Liberty - Liberty	Distribution *	69.00	12.47	
19	Liberty Road - Lexington	Distribution *	69.00	12.47	
20	London - London	Distribution *	69.00	12.47	
21	Loudon Ave. - Lexington	Distribution *	138.00	12.47	
22	Madisonville GE 12KV	Distribution *	69.00	12.47	
23	Madisonville HP 12KV	Distribution *	69.00	12.47	
24	Madisonville North 4KV	Distribution *	69.00	4.16	
25	Madisonville West 12KV	Distribution *	69.00	12.47	
26	Madisonville East 12KV	Distribution *	69.00	12.47	
27	Manchester South	Distribution *	69.00	12.47	
28	Marion South - Marion	Distribution *	69.00	12.47	
29	Maysville Mid - Maysville	Distribution *	69.00	4.16	
30	McCoy Avenue 12KV	Distribution *	69.00	12.47	
31	McKee Road 12KV	Distribution *	69.00	12.47	
32	Meldrum - Middlesboro	Distribution *	69.00	12.47	
33	Metal & Thermit - Carrollton	Distribution *	69.00	12.47	
34	Middlesboro #1 12KV	Distribution *	69.00	12.47	
35	Middlesboro #2 12KV	Distibution *	69.00	12.47	
36	Midway - Versailles	Distribution *	138.00	12.47	
37	Minor Farm 12KV	Distribution *	69.00	12.47	
38	Morehead - Morehead	Distribution *	69.00	12.47	
39	Morganfield Industrial - Morganfield	Distribution *	69.00	12.47	
40	Mt. Sterling - Mt. Sterling	Distribution *	69.00	12.47	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Utilities Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2008/Q4

SUBSTATIONS (Continued)

5. Show in columns (I), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.
6. Designate substations or major items of equipment leased from others, jointly owned with others, or operated otherwise than by reason of sole ownership by the respondent. For any substation or equipment operated under lease, give name of lessor, date and period of lease, and annual rent. For any substation or equipment operated other than by reason of sole ownership or lease, give name of co-owner or other party, explain basis of sharing expenses or other accounting between the parties, and state amounts and accounts affected in respondent's books of account. Specify in each case whether lessor, co-owner, or other party is an associated company.

Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	Line No.
14	1		NONE			1
37	2		NONE			2
23	1		NONE			3
37	1		NONE			4
14	1		NONE			5
75	2		NONE			6
45	2		NONE			7
14	1		NONE			8
14	3		NONE			9
14	1		NONE			10
14	1		NONE			11
14	1		NONE			12
14	1		NONE			13
14	1		NONE			14
45	2		NONE			15
45	2		NONE			16
28	1		NONE			17
14	1		NONE			18
37	1		NONE			19
45	2		NONE			20
37	1		NONE			21
23	1		NONE			22
14	1		NONE			23
23	1		NONE			24
23	1		NONE			25
14	1		NONE			26
14	1		NONE			27
14	1		NONE			28
14	1		NONE			29
14	1		NONE			30
14	1		NONE			31
14	1		NONE			32
14	1		NONE			33
28	2		NONE			34
28	2		NONE			35
14	1		NONE			36
14	1		NONE			37
14	1		NONE			38
14	1		NONE			39
14	1		NONE			40

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Utilities Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2008/Q4

SUBSTATIONS

1. Report below the information called for concerning substations of the respondent as of the end of the year.
2. Substations which serve only one industrial or street railway customer should not be listed below.
3. Substations with capacities of Less than 10 MVa except those serving customers with energy for resale, may be grouped according to functional character, but the number of such substations must be shown.
4. Indicate in column (b) the functional character of each substation, designating whether transmission or distribution and whether attended or unattended. At the end of the page, summarize according to function the capacities reported for the individual stations in column (f).

Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	Mt. Vernon - Mt. Vernon	Distribution *	69.00	12.47	
2	Muhlenburg Prison - Muhlenburg	Distribution *	69.00	12.47	
3	Norton East - Norton	Distribution *	69.00	12.47	
4	Oakhill - Earlington	Distribution*	69.00	34.50	
5	Okonite - Richmond	Distribution *	69.00	12.47	
6	Owingsville 12KV	Distribution *	69.00	12.47	
7	Oxford - Georgetown	Distribution *	69.00	12.47	
8	Paris - Paris	Distribution *	69.00	12.47	
9	Parker Seal 12KV - Winchester	Distribution *	69.00	12.47	
10	Parkers Mill 12KV	Distribution *	69.00	12.47	
11	Pepper Pike 12KV - Georgetown	Distribution *	34.50	12.47	
12	Picadome 12KV - Lexington	Distribution *	69.00	12.47	
13	Pineville 12KV	Distribution *	69.00	12.47	
14	Pocket - Norton	Distribution*	69.00	34.50	
15	Poor Valley - Pennington Gap	Distribution *	69.00	12.47	
16	Powderly - Muhlenburg	Distribution *	69.00	12.47	
17	Princeton - Princeton	Distribution*	69.00	34.50	
18	Proctor/Gamble 4KV	Distribution *	69.00	4.16	
19	Race Street - Lexington	Distribution *	69.00	12.47	
20	Radcliff - Radcliff	Distribution *	69.00	12.47	
21	Red House 12KV	Distribution *	69.00	12.47	
22	Reynolds - Lexington	Distribution *	138.00	12.47	
23	Richmond 12KV	Distribution *	69.00	12.47	
24	Richmond #3 12KV (EKU)	Distribution *	69.00	12.47	
25	Richmond East	Distribution *	69.00	12.47	
26	Richmond Industrial	Distribution *	69.00	12.47	
27	Richmond South	Distribution *	69.00	12.47	
28	Rockwell - Winchester	Distribution *	69.00	12.47	
29	Rogersville - Radcliff	Distribution *	69.00	12.47	
30	Rumsey - Earlington	Distribution*	34.50	34.50	
31	Salem - Earlingtom	Distribution*	69.00	34.50	
32	Shannon Run 12KV	Distribution *	69.00	12.47	
33	Sharon - Augusta	Distribution *	69.00	12.47	
34	Shavers Chap 12KV	Distribution *	69.00	12.47	
35	Shelbyville North12KV	Distribution *	69.00	12.47	
36	Shelbyville East	Distribution *	69.00	12.47	
37	Shelbyville South	Distribution *	69.00	12.47	
38	Shun Pike 12KV	Distribution*	69.00	12.47	
39	Simpsonville - Shelbyville	Distribution*	69.00	12.47	
40	Somerset #2 4KV	Distribution *	69.00	4.16	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Utilities Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2008/Q4

SUBSTATIONS (Continued)

5. Show in columns (I), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.
6. Designate substations or major items of equipment leased from others, jointly owned with others, or operated otherwise than by reason of sole ownership by the respondent. For any substation or equipment operated under lease, give name of lessor, date and period of lease, and annual rent. For any substation or equipment operated other than by reason of sole ownership or lease, give name of co-owner or other party, explain basis of sharing expenses or other accounting between the parties, and state amounts and accounts affected in respondent's books of account. Specify in each case whether lessor, co-owner, or other party is an associated company.

Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	Line No.
14	1		NONE			1
14	1		NONE			2
14	1		NONE			3
20	1		NONE			4
14	1		NONE			5
14	1		NONE			6
14	1		NONE			7
14	1		NONE			8
23	1		NONE			9
45	2		NONE			10
14	1		NONE			11
23	1		NONE			12
28	2		NONE			13
20	1		NONE			14
14	1		NONE			15
14	1		NONE			16
13	1		NONE			17
14	1		NONE			18
14	1		NONE			19
23	1		NONE			20
14	1		NONE			21
77	2		NONE			22
45	2		NONE			23
37	2		NONE			24
23	1		NONE			25
23	1		NONE			26
23	1		NONE			27
23	1		NONE			28
23	1		NONE			29
13	1		NONE			30
14	1		NONE			31
14	1		NONE			32
14	1		NONE			33
14	1		NONE			34
23	1		NONE			35
23	1		NONE			36
37	2		NONE			37
14	1		NONE			38
14	1		NONE			39
14	1		NONE			40

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Utilities Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2008/Q4

SUBSTATIONS

1. Report below the information called for concerning substations of the respondent as of the end of the year.
2. Substations which serve only one industrial or street railway customer should not be listed below.
3. Substations with capacities of Less than 10 MVa except those serving customers with energy for resale, may be grouped according to functional character, but the number of such substations must be shown.
4. Indicate in column (b) the functional character of each substation, designating whether transmission or distribution and whether attended or unattended. At the end of the page, summarize according to function the capacities reported for the individual stations in column (f).

Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	Somerset #3 12KV	Distribution *	69.00	12.47	
2	Somerset South	Distribution *	69.00	12.47	
3	Springfield - Campbellsville	Distribution *	69.00	12.47	
4	St. Paul 12KV	Distribution *	69.00	12.47	
5	Stanford 12KV	Distribution *	69.00	12.47	
6	Stanford North 12KV	Distribution *	69.00	12.47	
7	Stonewall 12KV - Lexington	Distribution *	69.00	12.47	
8	Sylvania 12KV - Winchester	Distribution *	69.00	12.47	
9	Taylorsville - Shelbyville	Distribution*	69.00	12.47	
10	Toyota North	Distribution *	138.00	13.20	
11	Toyota South	Distribution *	138.00	13.20	
12	Trafton Ave. 12KV - Lexington	Distribution *	69.00	12.47	
13	Trafton Ave. 4KV - Lexington	Distribution *	69.00	4.16	
14	UK Scott 12KV	Distribution *	69.00	12.47	
15	UK Medical Center - Lexington	Distribution *	69.00	12.47	
16	UK West - Lexington	Distribution *	69.00	13.09	
17	Union Underwear - Russell Springs	Distribution *	69.00	12.47	
18	Vaksdahl Avenue 12KV	Distribution *	69.00	12.47	
19	Verda - Harlan	Distribution *	69.00	12.47	
20	Versailles West 12KV - Versailles	Distribution *	69.00	12.47	
21	Versailles Bypass - Versailles	Distribution *	69.00	12.47	
22	Viley Road - Lexington	Distribution *	138.00	12.47	
23	Vine Street 12KV - Lexington	Distribution *	69.00	12.47	
24	Waitsboro - Somerset	Distribution *	69.00	12.47	
25	Warsaw East - Owenton	Distribution *	69.00	12.47	
26	West Cliff 34.5KV	Distribution*	69.00	34.50	
27	West Hickman - Lexington	Distribution *	69.00	12.47	
28	West High Street 12KV - Lexington	Distribution *	69.00	12.47	
29	Westvaco 13.8KV	Distribution *	69.00	13.80	
30	Wickliffe 13.8KV	Distribution *	69.00	13.80	
31	Wilson Downing - Lexington	Distribution *	69.00	12.47	
32	Williamsburg South - Williamsburg	Distribution *	69.00	12.47	
33	Wilmore - Versailles	Distribution *	69.00	12.47	
34	Winchester Industrial 12KV - Winchester	Distribution *	69.00	12.47	
35	Winchester WW 12KV	Distribution *	69.00	12.47	
36	Wise - Norton	Distribution *	69.00	12.47	
37	Woodlawn 12KV	Distribution*	69.00	12.47	
38	260 Stations Less Than 10,000 KVA				
39					
40	Total Distribution		16247.50	3010.00	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Utilities Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2008/Q4

SUBSTATIONS (Continued)

5. Show in columns (I), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.
6. Designate substations or major items of equipment leased from others, jointly owned with others, or operated otherwise than by reason of sole ownership by the respondent. For any substation or equipment operated under lease, give name of lessor, date and period of lease, and annual rent. For any substation or equipment operated other than by reason of sole ownership or lease, give name of co-owner or other party, explain basis of sharing expenses or other accounting between the parties, and state amounts and accounts affected in respondent's books of account. Specify in each case whether lessor, co-owner, or other party is an associated company.

Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	Line No.
14	1		NONE			1
14	1		NONE			2
14	1		NONE			3
45	2		NONE			4
14	1		NONE			5
14	1		NONE			6
37	1		NONE			7
23	1		NONE			8
14	1		NONE			9
84	3		NONE			10
84	3		NONE			11
14	1		NONE			12
14	1		NONE			13
37	1		NONE			14
65	2		NONE			15
14	1		NONE			16
28	2		NONE			17
14	1		NONE			18
14	1		NONE			19
23	1		NONE			20
45	2		NONE			21
39	1		NONE			22
14	1		NONE			23
14	1		NONE			24
14	1		NONE			25
21	1		NONE			26
23	1		NONE			27
28	2		NONE			28
67	3		NONE			29
14	1		NONE			30
45	2		NONE			31
14	1		NONE			32
14	1		NONE			33
23	1		NONE			34
14	1		NONE			35
23	1		NONE			36
14	1		NONE			37
1596	392		NONE			38
						39
6865	679					40

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Utilities Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2008/Q4

SUBSTATIONS

1. Report below the information called for concerning substations of the respondent as of the end of the year.
2. Substations which serve only one industrial or street railway customer should not be listed below.
3. Substations with capacities of Less than 10 MVa except those serving customers with energy for resale, may be grouped according to functional character, but the number of such substations must be shown.
4. Indicate in column (b) the functional character of each substation, designating whether transmission or distribution and whether attended or unattended. At the end of the page, summarize according to function the capacities reported for the individual stations in column (f).

Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1					
2	* Unattended				
3					
4					
5	Summary				
6	Transmission 113				
7	Distribution 483				
8	Total 596				
9					
10					
11					
12					
13					
14					
15					
16					
17					
18					
19					
20					
21					
22					
23					
24					
25					
26					
27					
28					
29					
30					
31					
32					
33					
34					
35					
36					
37					
38					
39					
40					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Utilities Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2008/Q4

SUBSTATIONS (Continued)

5. Show in columns (I), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.
6. Designate substations or major items of equipment leased from others, jointly owned with others, or operated otherwise than by reason of sole ownership by the respondent. For any substation or equipment operated under lease, give name of lessor, date and period of lease, and annual rent. For any substation or equipment operated other than by reason of sole ownership or lease, give name of co-owner or other party, explain basis of sharing expenses or other accounting between the parties, and state amounts and accounts affected in respondent's books of account. Specify in each case whether lessor, co-owner, or other party is an associated company.

Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	Line No.
						1
						2
						3
						4
						5
17700	115	18				6
6865	679					7
24565	794	18				8
						9
						10
						11
						12
						13
						14
						15
						16
						17
						18
						19
						20
						21
						22
						23
						24
						25
						26
						27
						28
						29
						30
						31
						32
						33
						34
						35
						36
						37
						38
						39
						40

BLANK

Schedule Page: 426 Line No.: 15 Column: b
(G) Generation

Schedule Page: 426 Line No.: 16 Column: b
(G) Generation

Schedule Page: 426 Line No.: 19 Column: b
(G) Generation

Schedule Page: 426 Line No.: 20 Column: b
(G) Generation

Schedule Page: 426 Line No.: 32 Column: b
(G) Generation

Schedule Page: 426.1 Line No.: 7 Column: b
(G) Generation

Schedule Page: 426.1 Line No.: 8 Column: b
(G) Generation

Schedule Page: 426.1 Line No.: 9 Column: b
(G) Generation

Schedule Page: 426.1 Line No.: 13 Column: b
(G) Generation

Schedule Page: 426.1 Line No.: 18 Column: b
(G) Generation

Schedule Page: 426.2 Line No.: 36 Column: b
(G) Generation

Schedule Page: 426.2 Line No.: 37 Column: b
(G) Generation

Schedule Page: 426.2 Line No.: 40 Column: b
Commissioned in 2008.

INDEX

Schedule	Page No.

INDEX (continued)

Schedule	Page No.

Kentucky Utilities Company
Case No. 2009-00548
Historical Test Period Filing Requirements

Filing Requirement
807 KAR 5:001 Section 10(6)(n)
Sponsoring Witness: Shannon L. Charnas

Description of Filing Requirement:

A summary of the utility's latest depreciation study with schedules by major plant accounts, except that telecommunications utilities that have adopted the commission's average depreciation rates shall provide a schedule that identifies the current and test period depreciation rates used by major plant accounts. If the required information has been filed in another commission case a reference to that case's number and style will be sufficient.

Response:

On December 28, 2007, the Company filed with the Commission an application filing a new depreciation study (with schedules by major plant accounts) and accompanying testimony in Case No. 2007-00565, *In the Matter of: Application of Kentucky Utilities Company to File Depreciation Study.* On July 29, 2008, the Company filed with the Commission an application for an adjustment of base rates in Case No. 2008-00251, *In the Matter of: Application of Kentucky Utilities Company for an Adjustment of its Base Rates.* By order dated August 22, 2008, the Commission consolidated Case No. 2007-00565 and Case No. 2008-00251. The cases were settled and the Commission approved the settlement by order dated February 5, 2009, with the settlement agreement attached. Exhibit 7 to the settlement agreement is a schedule of the Company's depreciation rates to which the parties agreed and which the Commission approved.

On August 7, 2009, the Company and Louisville Gas and Electric Company filed a joint application for approval of depreciation rates for their Trimble County Unit 2 generating station. Case No. 2009-00329, *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.* The proposed rates are set forth in a letter attached to the application in Case No. 2009-00329 as Exhibit 1. By interim order dated December 23, 2009, the Commission approved, on an interim basis, the depreciation rates proposed by the Company and Louisville Gas and Electric Company. Case No. 2009-00329 is still pending.

Kentucky Utilities Company
Case No. 2009-00548
Historical Test Period Filing Requirements

Filing Requirement
807 KAR 5:001 Section 10(6)(o)
Sponsoring Witness: Valerie L. Scott

Description of Filing Requirement:

A list of all commercially available or in-house developed computer software, programs, and models used in the development of the schedules and work papers associated with the filing of the utility's application. This list shall include each software, program, or model; what the software, program, or model was used for; identify the supplier of each software, program, or model; a brief description of the software, program, or model; the specifications for the computer hardware and the operating system required to run the program.

Response:

See attached.

Computer Software, Programs, and Models

Supplier	Microsoft	Microsoft	Microsoft	Prime Group	Adobe
Software/Program/Model	Word 2003 Word 2007	Excel 2003 Excel 2007	PowerPoint 2003 PowerPoint 2007	Proprietary Model SAS Version 9.2 Matlab 2009b	Acrobat Version 7.0 Acrobat Standard 7.1 Acrobat Pro Version 9.0 Acrobat Reader 9.1
Use in Application	Tab: Statutory Notice, Application, Financial Exhibit, Table of Contents and 1-46	Various attachments including: Financial Exhibit, 11, 14, 20, 21, 23-29, 34, 37, 39, 42, 45 and 46	Tab: 21	Tab: 20, 21, 26, 40 and 46	Tab #: 1-19, 21, 23-26, 30-32, 35, 36, 38, 40-43 and 46
Description	Word processing program	Spreadsheet and graphing program	Presentation program	Cost allocation program and temperature normalization	Preserve and secure the layout of documents created in other applications
Hardware Specifications	Pentium 233 Mhz processor or greater	Pentium 233 Mhz processor or greater	Pentium 233 Mhz processor or greater	Intel Pentium 4 or greater	Personal or multimedia computer with Intel Pentium or equivalent processor
Operating System Specifications	Microsoft Office XP, Windows XP or higher	Microsoft Office XP, Windows XP or higher	Microsoft Office XP, Windows XP or higher	Windows XP or higher	Microsoft Windows NT with Service Pack 6 or 6a or higher operating system

Kentucky Utilities Company
Case No. 2009-00548
Historical Test Period Filing Requirements

Filing Requirement
807 KAR 5:001 Section 10(6)(p)
Sponsoring Witness: S. Bradford Rives

Description of Filing Requirement:

Prospectuses of the most recent stock or bond offerings.

Response:

See attached.

KU Prospectus – Environmental Facilities Revenue Bonds and Environmental Facilities Revenue Refunding Bonds

Prospectus Dated: December 11, 2008

NOT A NEW ISSUE **BOOK-ENTRY ONLY**

On February 23, 2007 and October 17, 2008, the dates on which the Bonds were originally issued, Bond Counsel delivered its opinions that stated that, subject to the conditions and exceptions set forth under the caption "Tax Treatment," under then current law, interest on each series of Bonds would be excludable from the gross income of the recipients thereof for federal income tax purposes, except that no opinion was expressed regarding such exclusion from gross income with respect to any Bond during any period in which it is held by a "substantial user" or a "related person" of the related Project as such terms are used in Section 147(a) of the Internal Revenue Code of 1986, as amended (the "Code"). Interest on each series of Bonds will be an item of tax preference in determining alternative minimum taxable income for individuals and corporations under the Code. Such interest may be subject to certain federal income taxes imposed on certain corporations, including imposition of the branch profits tax on a portion of such interest. Bond Counsel was further of the opinion that interest on each series of Bonds would be excludable from the gross income of the recipients thereof for Kentucky income tax purposes and that, under then current law, the principal of each series of Bonds would be exempt from ad valorem taxes in Kentucky. Such opinions have not been updated as of the date hereof and no continuing tax exemption opinions are expressed by Bond Counsel. However, in connection with the conversion of the interest rate mode on each series of Bonds to the Weekly Rate, as described in this Reoffering Circular, Bond Counsel will deliver its opinions to the effect that the conversion of the interest rate on each series of Bonds and the delivery of a letter of credit (a) is authorized or permitted by the Act and the related Indenture and (b) will not adversely affect the validity of the Bonds or any exclusion of the interest thereon from the gross income of the owners of the Bonds for federal income tax purposes. See "Tax Treatment" in this Reoffering Circular.

$54,000,000
County of Carroll, Kentucky
Environmental Facilities Revenue Refunding Bonds, 2006 Series B
(Kentucky Utilities Company Project)
Due: October 1, 2034

$77,947,405
County of Carroll, Kentucky
Environmental Facilities Revenue Bonds 2008 Series A
(Kentucky Utilities Company Project)
Due: February 1, 2032

Conversion Date: December 19, 2008

The Bonds of each series (individually, the "2006 Series B Bonds" and the "2008 Series A Bonds" and, collectively, the "Bonds") are special and limited obligations of the County of Carroll, Kentucky (the "Issuer"), payable by the Issuer solely from and secured by payments to be received by the Issuer pursuant to separate Loan Agreements with

Kentucky Utilities Company

(the "Company"), except as payable from proceeds of such Bonds or investment earnings thereon. The Bonds do not constitute general obligations of the Issuer or a charge against the general credit or taxing powers thereof or of the Commonwealth of Kentucky or any other political subdivision of Kentucky. The Bonds will not be entitled to the benefits of any financial guaranty insurance policies.

The 2006 Series B Bonds were originally issued on February 23, 2007 and the 2008 Series A Bonds were originally issued on October 17, 2008, each as a separate series. The 2006 Series B Bonds currently bear interest at a Dutch Auction Rate, and the 2008 Series A Bonds currently bear interest at a Flexible Rate. Pursuant to the Indentures under which the Bonds were issued, the Company has elected to convert the interest rate mode on each of the 2006 Series B Bonds and the 2008 Series A Bonds to a Weekly Rate, effective as of December 19, 2008 (the "Conversion Date"). The Bonds are subject to mandatory purchase on the Conversion Date and are being reoffered hereby. Banc of America Securities LLC will serve as the Remarketing Agent for the Bonds.

From and after the Conversion Date through December 18, 2009 (the Letter of Credit (as defined below) expiration date, subject to extension or earlier termination), payment of the principal of and interest on the Bonds when due will be paid with funds drawn under an irrevocable transferable direct pay letter of credit (the "Letter of Credit") issued by

COMMERZBANK AG, NEW YORK BRANCH

The Letter of Credit will permit the Trustee to draw with respect to the Bonds up to an amount sufficient to pay (i) the principal thereof (or that portion of the purchase price corresponding to principal) plus (ii) interest thereon (or that portion of the purchase price corresponding to interest) at an assumed rate of 15% per annum for at least 45 days.

From the Conversion Date, each series of Bonds will bear interest at a Weekly Rate, determined by the Remarketing Agent in accordance with the applicable Indenture, payable on the first Business Day of each calendar month, commencing on January 2, 2009. The interest rate period, interest rate and Interest Rate Mode for each series of Bonds will be subject to change under certain conditions, as described in this Reoffering Circular. The Bonds of each series are subject to optional redemption, extraordinary optional redemption, in whole or in part, and mandatory redemption following a determination of taxability prior to maturity, as described in this Reoffering Circular. The Bonds of each series are subject to mandatory purchase on any date on which the Bonds are converted to a different Interest Rate Mode and upon the expiration of the Letter of Credit or any Alternate Credit Facility.

The Bonds of each series are separate series, and the sale and delivery of one series is not dependent on the sale and delivery of any other series.

The Bonds are registered in the name of Cede & Co., as registered owner and nominee for The Depository Trust Company ("DTC"), New York, New York. DTC will act as securities depository. Except as described herein, purchases of beneficial ownership interests in the Bonds will be made in book-entry-only form in denominations of $100,000 and multiples thereof; provided that one 2008 Series A Bond may be in the denomination of, or include an additional, $47,405. Purchasers will not receive certificates representing their beneficial interests in the Bonds. See the information contained under the caption "Summary of the Bonds—Book-Entry-Only System" below. The principal of, premium, if any, and interest on the Bonds will be paid by Deutsche Bank Trust Company Americas, as Trustee, to Cede & Co., as long as Cede & Co. is the registered owner of the Bonds. Disbursement of such payments to the DTC Participants is the responsibility of DTC, and disbursement of such payments to the purchasers of beneficial ownership interests is the responsibility of DTC's Direct and Indirect Participants, as described below.

PRICE: 100%

The Bonds are reoffered subject to prior sale, withdrawal or modification of the offer without notice (provided, however, that any such notice of withdrawal must be given on the Business Day prior to the Conversion Date) and to the approval of legality by Stoll Keenon Ogden PLLC, Louisville, Kentucky, as Bond Counsel and upon satisfaction of certain conditions. Certain legal matters will be passed upon for the Company by its counsel, Jones Day, Chicago, Illinois, and John R. McCall, Esq., Executive Vice President, General Counsel, Corporate Secretary and Chief Compliance Officer of the Company, for the Issuer by its County Attorney, and for the Remarketing Agent by its counsel, Winston & Strawn LLP, Chicago, Illinois. It is expected that the Bonds will be available for redelivery to DTC in New York, New York on or about December 19, 2008.

Banc of America Securities LLC

Dated: December 11, 2008

No dealer, broker, salesman or other person has been authorized by the Issuer, the Company or the Remarketing Agent to give any information or to make any representation with respect to the Bonds, other than those contained in this Reoffering Circular, and, if given or made, such other information or representation must not be relied upon as having been authorized by any of the foregoing. The Remarketing Agent has provided the following sentence for inclusion in this Reoffering Circular. The Remarketing Agent has reviewed the information in this Reoffering Circular in accordance with, and as part of, its responsibilities to investors under the federal securities laws as applied to the facts and circumstances of this transaction, but the Remarketing Agent does not guarantee the accuracy or completeness of such information. The information and expressions of opinion herein are subject to change without notice and neither the delivery of this Reoffering Circular nor any sale made hereunder shall, under any circumstances, create any implication that there has been no change in the affairs of the parties referred to above since the date hereof. The information set forth herein with respect to the Issuer has been obtained from the Issuer, and all other information has been obtained from the Company and from other sources that are believed to be reliable, but it is not guaranteed as to accuracy or completeness by, and is not to be construed as a representation by, the Remarketing Agent.

In connection with the reoffering of the Bonds, the Remarketing Agent may over-allot or effect transactions which stabilize or maintain the market prices of the Bonds at levels above those that might otherwise prevail in the open market. Such stabilizing, if commenced, may be discontinued at any time.

IN MAKING AN INVESTMENT DECISION, INVESTORS MUST RELY ON THEIR OWN EXAMINATION OF THE TERMS OF THE REOFFERING, INCLUDING THE MERITS AND RISKS INVOLVED. THESE SECURITIES HAVE NOT BEEN RECOMMENDED BY ANY FEDERAL OR STATE SECURITIES COMMISSION OR REGULATORY AUTHORITY. FURTHERMORE, THE FOREGOING AUTHORITIES HAVE NOT CONFIRMED THE ACCURACY OR DETERMINED THE ADEQUACY OF THIS DOCUMENT. ANY REPRESENTATION TO THE CONTRARY IS A CRIMINAL OFFENSE.

Table of Contents

$54,000,000	$77,947,405
County of Carroll, Kentucky	**County of Carroll, Kentucky**
Environmental Facilities Revenue	**Environmental Facilities Revenue Bonds**
Refunding Bonds, 2006 Series B	**2008 Series A**
(Kentucky Utilities Company Project)	**(Kentucky Utilities Company Project)**
Due: October 1, 2034	**Due: February 1, 2032**

Introductory Statement

This Reoffering Circular, including the cover page and appendices, is provided to furnish information in connection with the reoffering by the County of Carroll, Kentucky (the "Issuer") of its (i) Environmental Facilities Revenue Refunding Bonds, 2006 Series B (Kentucky Utilities Company Project, in the aggregate principal amount of $54,000,000 (the "2006 Series B Bonds"), issued pursuant to an Indenture of Trust dated as of October 1, 2006 (the "2006 Series B Indenture") between the Issuer and Deutsche Bank Trust Company Americas (the "2006 Series B Trustee"), as Trustee, Paying Agent and Bond Registrar, as the same has been amended and restated as of September 1, 2008, and (ii) Environmental Facilities Revenue Bonds, 2008 Series A (Kentucky Utilities Company Project), in the aggregate principal amount of $77,947,405 (the "Bonds") issued pursuant to an Indenture of Trust dated as of August 1, 2008 (the "2008 Series A Indenture" and, collectively with the 2006 Series B Indenture, the "Indentures") between the Issuer and Deutsche Bank Trust Company Americas (the "2008 Series A Trustee" and, collectively with the 2006 Series B Trustee, the "Trustee"), as Trustee, Paying Agent and Bond Registrar.

Pursuant to separate Loan Agreements by and between Kentucky Utilities Company (the "Company") and the Issuer, dated as of October 1, 2006 (as the same have been amended and restated as of September 1, 2008 pursuant to an ordinance of the Issuer adopted October 28, 2008), with respect to the 2006 Series B Bonds (the "2006 Series B Loan Agreement"), and August 1, 2008 (pursuant to an ordinance of the Issuer adopted September 23, 2008) with respect to the 2008 Series A Bonds (the "2008 Series A Loan Agreement" and, collectively with the 2006 Series B Loan Agreement, the "Loan Agreements"), proceeds from the sale of the Bonds, other than accrued interest, if any, paid by the initial purchasers thereof, were loaned by the Issuer to the Company. The Loan Agreements are separate undertakings by and between the Company and the Issuer.

The Company will continue to repay the loans under the 2006 Series B Loan Agreement and the 2008 Series A Loan Agreement by making payments to the applicable Trustee in sufficient amounts to pay the principal of and interest and any premium on, and purchase price of, the applicable series of Bonds. See "Summary of the Loan Agreement — General." Pursuant to the applicable Indenture, the Issuer's rights under the applicable Loan Agreement (other than with respect to certain indemnification and expense payments and notification rights) were assigned to the applicable Trustee as security for the applicable series of Bonds.

The proceeds of the 2006 Series B Bonds were applied to pay and discharge all of the $54,000,000 outstanding principal amount of County of Carroll, Kentucky, Collateralized Solid

Waste Disposal Facilities Revenue Bonds (Kentucky Utilities Company Project) 1994 Series A," dated November 23, 1994, previously issued by the Issuer to finance certain solid waste disposal facilities owned by the Company (the "2006 Series B Project"). The proceeds of the 2008 Series A Bonds were applied to (i) finance the acquisition, construction, installation and equipping of certain solid waste disposal facilities owned by the Company in the amount of $18,026,265 and (ii) pay and discharge all of the $13,266,950 outstanding principal amount of County of Carroll, Kentucky, Environmental Facilities Revenue Bonds, 2005 Series A (Kentucky Utilities Company Project), $13,266,950 outstanding principal amount of County of Carroll, Kentucky, Environmental Facilities Revenue Bonds, 2005 Series B (Kentucky Utilities Company Project), $16,693,620 outstanding principal amount of County of Carroll, Kentucky, Environmental Facilities Revenue Bonds, 2006 Series A (Kentucky Utilities Company Project) and $16,693,620 outstanding principal amount of County of Carroll, Kentucky, Environmental Facilities Revenue Bonds, 2006 Series C (Kentucky Utilities Company Project), all previously issued by the Issuer to finance certain solid waste disposal facilities (collectively, the "2008 Series A Project") owned by the Company. For information regarding the Project, see "The Project."

The Company is an operating subsidiary of E.ON U.S. LLC (formerly known as LG&E Energy LLC) and E.ON AG (the "Parents"). See "Appendix A — Kentucky Utilities Company — Financial Statements and Additional Information." The Parents have no obligation to make any payments due under the Loan Agreements or any other payments of principal, interest, premium or purchase price of the Bonds.

The Bonds are being converted to bear interest at a Weekly Rate, but may be subsequently converted again to bear interest at a Daily Rate, a Weekly Rate, a Flexible Rate, a Semi-Annual Rate, an Annual Rate, a Long Term Rate or with respect to the 2006 Series B Bonds, a Dutch Auction Rate. **This Reoffering Circular pertains only to the Bonds during such period of time that they bear interest at the Weekly Rate.**

The Bonds are special and limited obligations of the Issuer, and the Issuer's obligation to pay the principal of and interest and any premium on, and purchase price of, each series of the Bonds is limited solely to the revenues and other amounts received by the applicable Trustee under the applicable Indenture pursuant to the applicable Loan Agreement (and the applicable Letter of Credit (as defined below). The Bonds do not constitute an indebtedness, general obligation or pledge of the faith and credit or taxing power of the Issuer, the Commonwealth of Kentucky or any political subdivision thereof. The Bonds are not entitled to the benefits of any financial guaranty insurance policies.

Concurrently with, and as a condition to, the conversion and reoffering of the Bonds, the Company will cause to be delivered separate irrevocable transferable direct pay letters of credit (the "Letters of Credit") with respect to each of the 2006 Series B Bonds and the 2008 Series A Bonds, issued by Commerzbank AG, New York Branch (the "Bank"), to provide for the timely payment of principal of and accrued interest (calculated for at least 45 days at the maximum rate of 15% per annum) on, and purchase price of, the Bonds. The Company will be required to reimburse the Bank for all amounts drawn by the Trustee under the Letters of Credit pursuant to the terms of separate Reimbursement Agreements, to be dated as of December 19, 2008 (collectively, the "Reimbursement Agreement"), with respect to each of the 2006 Series B Bonds and the 2008 Series A Bonds, between the Company and the Bank. Each Letter of Credit will expire on December 18, 2009, unless extended or earlier terminated.

Upon expiration of a Letter of Credit or any Alternate Credit Facility, the related series of Bonds will be subject to mandatory tender for purchase. See "Summary of the Bonds — Mandatory Purchases of Bonds — Mandatory Purchase upon Delivery, Cancellation, Substitution, Extension, Termination or Expiration of Any Credit Facility or Replacement with an Alternate Credit Facility." As used in this Reoffering Circular, "Bank" or "Credit Facility Issuer" refers to the Bank as the issuer of the applicable Letter of Credit and any other issuer of any Alternate Credit Facility delivered in accordance with the applicable Indenture; "Letter of Credit" or "Credit Facility" means the applicable Letter of Credit delivered under the applicable Indenture and, as applicable, any Alternate Credit Facility which may be subsequently delivered in accordance with such Indenture; and "Reimbursement Agreement" refers to the applicable initial Reimbursement Agreement under which the related Letter of Credit is provided and any subsequent agreement entered into between the Company and any other party in connection with the delivery of any Alternate Credit Facility.

Banc of America Securities LLC will be appointed under the Indentures to serve as Remarketing Agent for the Bonds. Any Remarketing Agent may resign or be removed and a successor Remarketing Agent may be appointed in accordance with the terms of the applicable Indenture and the applicable Remarketing Agreement for the Bonds between such Remarketing Agent and the Company.

Brief descriptions of the Company, the Issuer, the Bonds, the Loan Agreements, the Indentures, the Letters of Credit and the Reimbursement Agreements are included in this Reoffering Circular. Appendix A to this Reoffering Circular has been furnished by the Company. The Issuer and Bond Counsel assume no responsibility for the accuracy or completeness of such Appendix A or such information. Appendix B to this Reoffering Circular contains the opinions of Bond Counsel delivered on the dates on which each series of the Bonds were initially issued, and the proposed forms of opinions of Bond Counsel to be delivered in connection with the conversion of each series of the Bonds to the Weekly Rate. Appendix C to this Reoffering Circular contains information about the Bank. The Issuer and Bond Counsel assume no responsibility for the accuracy or completeness of such Appendix C or such information. Such descriptions and information do not purport to be complete, comprehensive or definitive and are not to be construed as a representation or a guaranty of accuracy or completeness. All references herein to the documents are qualified in their entirety by reference to such documents, and references herein to a series of Bonds are qualified in their entirety by reference to the definitive form thereof included in the applicable Indenture. Copies of the Loan Agreements, the Indentures, the Letters of Credit and the Reimbursement Agreements will be available for inspection at the principal corporate trust office of the Trustee party thereto. Certain information relating to The Depository Trust Company ("DTC") and the book-entry-only system has been furnished by DTC. All statements herein are qualified in their entirety by reference to each such document and, with respect to the enforceability of certain rights and remedies, to laws and principles of equity relating to or affecting generally the enforcement of creditors' rights.

The Projects

2006 Series B Project

The 2006 Series B Project has been completed, placed in operation and is the property of the Company and consists of certain solid waste disposal facilities at the Company's Ghent Generating Station located in Carroll County, Kentucky for the collection, storage, treatment processing and final disposal of solid wastes.

2008 Series A Project

The 2008 Series A Project consists of the Construction Project and the Refunding Project.

Construction Project. The "Construction Project" consists of certain solid waste disposal facilities at the Company's Ghent Generating Station, Unit 1, located in Carroll County, Kentucky for the collection, storage, treatment and final disposal of solid wastes ("Ghent Generating Station"). The Company has begun construction and fabrication of the Construction Project. The Kentucky Public Service Commission has issued a Certificate of Convenience and Necessity ("CCN") that authorizes construction of the Construction Project. When constructed, the Construction Project will be the property of the Company.

Refunding Project. The "Refunding Project" consists of certain solid waste disposal facilities at the Ghent Generating Station for the collection, storage, treatment and final disposal of solid wastes. The Refunding Project has been completed, placed in operation and Completion Certificates in respect thereof have been issued. The Refunding Project has and will contribute to the collection, storage, treatment, processing and final disposal of solid wastes.

Separate Series

The 2006 Series B Bonds and the 2008 Series A Bonds are separate series and optional or mandatory redemption of any series may be made in the manner described below without the redemption of the other series. Similarly, a default under one of the series of Bonds or one of the Loan Agreements will not necessarily constitute a default under the other series of Bonds or Loan Agreements. Each series of Bonds can bear interest at an Interest Rate Mode different from the Interest Rate Mode borne by the other series of Bonds. Unless specifically otherwise noted, any discussion herein and under the captions "Summary of the Bonds," "The Letter of Credit," "Security; Limitation of Liens," "Summary of the Loan Agreement," "Summary of the Indenture," "Enforceability of Remedies" and "Tax Treatment" applies equally, but separately, to the 2006 Series B Bonds and the 2008 Series A Bonds.

As used herein under such captions with respect to the 2006 Series B Bonds, the term "Project" shall mean the 2006 Series B Project, the term "Bonds" shall mean the 2006 Series B Bonds, the term "Loan Agreement" shall mean the 2006 Series B Loan Agreement pursuant to which the Issuer loaned the proceeds from the sale of the 2006 Series B Bonds to the Company, the term "Indenture" shall mean the 2006 Series B Indenture, the term "Remarketing Agent" shall mean Banc of America Securities LLC, the terms "Trustee" and "Tender Agent" shall mean the 2006 Series B Trustee and the term "Letter of Credit" shall mean the Letter of Credit delivered to the 2006 Series B Trustee.

As used herein under such captions with respect to the 2008 Series A Bonds, the term "Project" shall mean the 2008 Series A Project, the term "Bonds" shall mean the 2008 Series A Bonds, the term "Loan Agreement" shall mean the 2008 Series A Loan Agreement pursuant to which the Issuer loaned the proceeds from the sale of the 2008 Series A Bonds to the Company, the term "Indenture" shall mean the 2008 Series A Indenture, the term "Remarketing Agent" shall mean Banc of America Securities LLC, the terms "Trustee" and "Tender Agent" shall mean the 2008 Series A Trustee and the term "Letter of Credit" shall mean the Letter of Credit delivered to the 2008 Series A Trustee.

The Issuer

The Issuer is a public body corporate and politic duly created and existing as a county and political subdivision under the Constitution and laws of the Commonwealth of Kentucky. The Issuer is authorized by Sections 103.200 to 103.285, inclusive, of the Kentucky Revised Statutes (collectively, the "Act") to (a) convert and reoffer the Bonds and (b) amend and restate and continue to perform its obligations under the Loan Agreement and the Indenture. The Issuer, through its legislative body, the Fiscal Court, has adopted one or more ordinances authorizing the issuance of the Bonds and the execution and delivery of the related documents.

THE BONDS ARE SPECIAL AND LIMITED OBLIGATIONS PAYABLE SOLELY AND ONLY FROM CERTAIN SOURCES, INCLUDING AMOUNTS TO BE RECEIVED BY THE TRUSTEE FROM THE APPLICABLE LETTER OF CREDIT AND BY OR ON BEHALF OF THE ISSUER UNDER THE APPLICABLE LOAN AGREEMENT. THE BONDS DO NOT CONSTITUTE AN INDEBTEDNESS, GENERAL OBLIGATION OR PLEDGE OF THE FAITH AND CREDIT OR TAXING POWER OF THE ISSUER, THE COMMONWEALTH OF KENTUCKY OR ANY POLITICAL SUBDIVISION THEREOF, AND DO NOT GIVE RISE TO A PECUNIARY LIABILITY OF THE ISSUER OR A CHARGE AGAINST ITS GENERAL CREDIT OR TAXING POWERS.

Summary of the Bonds

Although each series of Bonds is an entirely separate issue and has been issued under a separate Indenture, each Indenture contains substantially the same terms and provisions except as otherwise noted below.

General

The Bonds will be issued in the aggregate principal amounts set forth on the cover page of this Reoffering Circular. The 2006 Series B Bonds will mature on October 1, 2034. The 2008 Series A Bonds will mature on February 1, 2032. The Bonds are also subject to optional redemption, extraordinary optional redemption, in whole or in part, and mandatory redemption prior to maturity as described in this Reoffering Circular.

The 2006 Series B Bonds currently bear interest at a Dutch Auction Rate, and the 2008 Series A Bonds currently bear interest at a Flexible Rate. Pursuant to the terms and provisions of the Indentures summarized below, the Company has exercised its option, effective December 19, 2008 (the "Conversion Date"), to convert the interest rate on the Bonds to a Weekly Rate. From and after the Conversion Date and reoffering of the Bonds, the Bonds will bear interest at a

Weekly Rate and will be payable on the first Business Day of each calendar month, commencing on January 2, 2009. The Bonds will continue to bear interest at the Weekly Rate until a Conversion to another Interest Rate Mode or until the maturity or redemption of the Bonds. The permitted Interest Rate Modes for the Bonds are (i) the "Flexible Rate," (ii) the "Daily Rate," (iii) the "Weekly Rate," (iv) the "Semi-Annual Rate," (v) the "Annual Rate," (vi) the "Long Term Rate" and (vii) with respect to the 2006 Series B Bonds, the "Dutch Auction Rate." Changes in the Interest Rate Mode will be effected, and notice of such changes will be given, as described below in "—Conversion of Interest Rate Modes and Changes of Long Term Rate Periods."

During each Rate Period for an Interest Rate Mode (other than the Dutch Auction Rate Mode with respect to the 2006 Series B Bonds), the interest rate or rates for the Bonds in that Interest Rate Mode, and Flexible Rate Periods for Bonds accruing interest at a Flexible Rate, will be determined by the Remarketing Agent in accordance with the Indenture; provided that the interest rate or rates borne by any Bonds may not exceed the lesser of (i) the maximum interest rate permitted by applicable law or (ii) 15% per annum. With respect to the 2006 Series B Bonds, the interest rate for the Bonds that bear interest at a Dutch Auction Rate will be determined in accordance with the procedures established pursuant to the Indenture.

Interest on the Bonds which bear interest at a Flexible Rate, Daily Rate or Weekly Rate will be computed on the basis of a year of 365 or 366 days, as appropriate, and paid for the actual number of days elapsed. Interest on the Bonds which bear interest at a Semi-Annual Rate, Annual Rate or Long Term Rate will be computed on the basis of a 360-day year, consisting of twelve 30-day months. With respect to the 2006 Series B Bonds, interest on the Bonds which bear interest at a Dutch Auction Rate will be computed on the basis of a 360-day year for the actual number of days elapsed. Interest payable on any Interest Payment Date will be payable to the registered owner of the Bond as of the Record Date for such payment; provided that in the case of Bonds bearing interest at the Flexible Rate, interest will be payable to the registered owner of such Bond on the Interest Payment Date therefor. The Record Date, in the case of interest accrued at a Daily Rate or Weekly Rate, will be the close of business on the Business Day immediately preceding each Interest Payment Date, in the case of interest accrued at a Semi-Annual Rate, Annual Rate or Long Term Rate, will be the close of business on the fifteenth day (whether or not a Business Day) of the month preceding each Interest Payment Date, and with respect to the 2006 Series B Bonds, in the case of interest accrued at a Dutch Auction Rate, will be the close of business on the second Business Day preceding each Interest Payment Date.

The Bonds initially will be issued solely in book-entry-only form through DTC (or its nominee, Cede & Co.). So long as the Bonds are held in the book-entry-only system, DTC or its nominee will be the registered owner or holder of the Bonds for all purposes of the Indenture, the Bonds and this Reoffering Circular. See "— Book-Entry-Only System" below. Individual purchases of book-entry interests in the Bonds will be made in book-entry-only form in (i) denominations of $100,000 or any integral multiple thereof, if bearing interest at the Daily Rate or the Weekly Rate, (ii) denominations of $100,000 or any integral multiple of $5,000 in excess of $100,000, if bearing interest at Flexible Rates, (iii) denominations of $5,000 and integral multiples thereof, if bearing interest at the Semi-Annual Rate, the Annual Rate or the Long Term Rate, or (iv) with respect to the 2006 Series B Bonds, denominations of $25,000 and integral multiples thereof, if bearing interest at a Dutch Auction Rate; provided, that with respect to the

2008 Series A Bonds, (i) if such 2008 Series A Bonds bear interest at the Daily Rate or the Weekly Rate, one 2008 Series A Bond may be in the denomination of, or include an additional $47,405 and (ii) if such 2008 Series A Bonds bear interest at the Semi-Annual Rate, the Annual Rate, the Long Term Rate or the Flexible Rate, one 2008 Series A Bond may be in the denomination of, or include an additional $2,405.

Except as otherwise described below for Bonds held in DTC's book-entry-only system, the principal or redemption price of the Bonds is payable at the designated corporate trust office in New York, New York, of the Trustee, as paying agent (the "Paying Agent"). Except as otherwise described below for Bonds held in DTC's book-entry-only system, interest on the Bonds is payable by check mailed to the owner of record; provided that interest payable on each Bond will be payable in immediately available funds by wire transfer within the continental United States or by deposit into a bank account maintained with the Trustee or a Paying Agent (i) if the Interest Rate Mode is the Daily Rate, the Weekly Rate or the Flexible Rate or, with respect to the 2006 Series B Bonds, the Dutch Auction Rate or (ii) at the written request of any owner of record holding at least $1,000,000 aggregate principal amount of the Bonds, if the Interest Rate Mode is the Semi-Annual Rate, Annual Rate or Long Term Rate, received by the Trustee, as bond registrar (the "Bond Registrar"), at least one Business Day prior to any Record Date. Except as otherwise described below for Bonds held in DTC's book-entry-only system, if the Interest Rate Mode is the Flexible Rate, interest payable on each Bond will be paid only upon presentation and surrender of such Bond.

Bonds may be transferred or exchanged for an equal total amount of Bonds of other authorized denominations upon surrender of such Bonds at the principal office of the Bond Registrar, accompanied by a written instrument of transfer or authorization for exchange in form and with guaranty of signature satisfactory to the Bond Registrar, duly executed by the registered owner or the owner's duly authorized attorney. Except as provided in the Indenture, the Bond Registrar will not be required to register the transfer or exchange of any Bond (i) during the fifteen days before any mailing of a notice of redemption of Bonds, (ii) after such Bond has been called for redemption or (iii) for which a registered owner has submitted a demand for purchase (see "— Purchases of Bonds on Demand of Owner" below), or which has been purchased (see "— Payment of Purchase Price" below). Registration of transfers and exchanges will be made without charge to the registered owners of Bonds, except that the Bond Registrar may require any registered owner requesting registration of transfer or exchange to pay any required tax or governmental charge.

The Bonds Are Not Insured

Upon the conversion of the Bonds to a Weekly Rate on the Conversion Date and the delivery of the Letter of Credit, the Financial Guaranty Insurance Policy (the "Bond Insurance Policy") issued by Ambac Assurance Corporation ("Ambac") with respect to the 2006 Series B Bonds on February 23, 2007 will have been irrevocably surrendered and cancelled. The 2008 Series A Bonds are currently not entitled to the benefits of any financial guaranty insurance policy. The Bonds described in this Reoffering Circular are not insured, and holders thereof will have no recourse to, under or against any bond insurance policy or bond insurer, including the aforementioned Bond Insurance Policy issued by Ambac.

Tender Agent

Owners may tender their Bonds, and in certain circumstances will be required to tender their Bonds, to the Tender Agent for purchase at the times and in the manner described herein under "— Summary of Certain Provisions of the Bonds," "— Purchases of Bonds on Demand of Owner" and "— Mandatory Purchases of Bonds." So long as the Bonds are held in DTC's book-entry-only system, the Trustee will act as Tender Agent under the Indenture. Any successor Tender Agent appointed pursuant to the Indenture will also be a Paying Agent.

Remarketing Agent

Banc of America Securities LLC will act as the Remarketing Agent with respect to the Bonds (the "Remarketing Agent"). The Remarketing Agent may resign or be removed and a successor Remarketing Agent may be appointed in accordance with the terms of the applicable Indenture and the applicable Remarketing Agreement for the Bonds between the Remarketing Agent and the Company.

Special Considerations Relating to the Remarketing Agent

The Remarketing Agent is paid by the Company.

The Remarketing Agent's responsibilities include determining the interest rate from time to time and remarketing Bonds that are optionally or mandatorily tendered by the owners thereof (subject, in each case, to the terms of the Remarketing Agreement), all as further described herein. The Remarketing Agent is appointed by the Issuer at the request of the Company and paid by the Company for its services. As a result, the interests of the Remarketing Agent may differ from those of existing holders and potential purchasers of Bonds.

The Remarketing Agent routinely purchases bonds for its own account.

The Remarketing Agent acts as remarketing agent for a variety of variable rate demand obligations and, in its sole discretion, routinely purchases such obligations for its own account in order to achieve a successful remarketing of the obligations (i.e., because there are otherwise not enough buyers to purchase the obligations) or for other reasons. The Remarketing Agent is permitted, but not obligated, to purchase tendered Bonds for its own account and, if it does so, it may cease doing so at any time without notice. The Remarketing Agent may also make a market in the Bonds by routinely purchasing and selling Bonds other than in connection with an optional or mandatory tender and remarketing. Such purchases and sales may be at or below par. However, the Remarketing Agent is not required to make a market in the Bonds. The Remarketing Agent may also sell any Bonds it has purchased to one or more affiliated investment vehicles for collective ownership or enter into derivative arrangements with affiliates or others in order to reduce its exposure to the Bonds. The purchase of Bonds by the Remarketing Agent may create the appearance that there is greater third party demand for the Bonds in the market than is actually the case. The practices described above also may result in fewer Bonds being tendered in a remarketing.

Bonds may be offered at different prices on any date.

As more fully described under the caption "— Determination of Interest Rates for Interest Rate Modes," the Remarketing Agent shall determine the minimum rate of interest per annum which in the opinion of the Remarketing Agent, would be necessary on and as of such day to remarket the Bonds in a secondary market transaction at a price equal to the principal amount thereof plus accrued interest thereon, if any, provided that such rate of interest shall not exceed 15% per annum. The interest rate will reflect, among other factors, the level of market demand for the Bonds (including whether the Remarketing Agent is willing to purchase Bonds for its own account). There may or may not be Bonds tendered and remarketed on a day that the rate on the Bonds are set, the Remarketing Agent may or may not be able to remarket any Bonds tendered for purchase on such date at par and the Remarketing Agent may sell Bonds at varying prices to different investors on such date or any other date. The Remarketing Agent is not obligated to advise purchasers in a remarketing if it does not have third party buyers for all of the Bonds at the remarketing price. In the event the Remarketing Agent owns any Bonds for its own account, it may, in its sole discretion in a secondary market transaction outside the tender process, offer such Bonds on any date, including the day that the rate on the Bonds are set, at a discount to par to some investors.

The ability to sell the Bonds other than through the tender process may be limited.

The Remarketing Agent may buy and sell Bonds other than through the tender process. However, it is not obligated to do so and may cease doing so at any time without notice and may require holders that wish to tender their Bonds to do so through the Trustee with appropriate notice. Thus, investors who purchase the Bonds, whether in a remarketing or otherwise, should not assume that they will be able to sell their Bonds other than by tendering the Bonds in accordance with the tender process.

Certain Definitions

As used herein, each of the following terms will have the meaning indicated.

"*Alternate Credit Facility*" means an irrevocable letter of credit, a municipal bond insurance policy, a surety bond, a line or lines of credit, a guarantee or other similar agreement or agreements or any other agreement or agreements used to provide liquidity or credit support for the Bonds, satisfactory to the Company and the Remarketing Agent and containing administrative provisions reasonably satisfactory to the Trustee, issued and delivered to the Trustee in accordance with the Indenture.

"*Annual Rate Period*" means the period beginning on, and including, the Conversion Date to the Annual Rate and ending on, and including, the day next preceding the second Interest Payment Date thereafter, and each successive twelve-month period (or portion thereof) thereafter until the day preceding the earlier of the Conversion to a different Interest Rate Mode or the maturity of the Bonds.

"*Beneficial Owner*" means the person in whose name a Bond is recorded as such by the respective systems of DTC and each DTC Participant (as defined herein) or the registered holder of such Bond if such Bond is not then registered in the name of Cede & Co.

"*Business Day*" means any day other than a Saturday or Sunday or legal holiday or a day on which banking institutions located in the City of New York, New York, or the New York Stock Exchange or banking institutions in the city in which the principal office of the Trustee, the Bond Registrar, the Tender Agent, the Paying Agent, the Auction Agent with respect to the 2006 Series B Bonds, the Company, the Credit Facility Issuer or the Remarketing Agent is located are authorized by law or executive order to close.

"*Conversion*" means any conversion from time to time in accordance with the terms of the Indenture of the Bonds from one Interest Rate Mode to another Interest Rate Mode.

"*Conversion Date*" means initially the date of original issuance of the Bonds, and thereafter means the date on which any Conversion becomes effective.

"*Credit Facility*" means an irrevocable direct pay letter of credit or other credit enhancement or liquidity support facility, or any combination thereof, delivered to and in favor of the Trustee for the benefit of the owners of the Bonds pursuant to the Indenture and designated as a "Credit Facility" under the Indenture, and includes the Initial Credit Facility or any Alternate Credit Facility delivered to the Trustee pursuant to the Indenture.

"*Credit Facility Issuer*" means the Initial Credit Facility Issuer and the issuer of any Credit Facility or Alternate Credit Facility subsequently in effect.

"*Daily Rate Period*" means the period beginning on, and including, the Conversion Date to the Daily Rate and ending on and including the day preceding the next Business Day and each period thereafter beginning on and including a Business Day and ending on and including the day preceding the next succeeding Business Day until the day preceding the earlier of the Conversion to a different Interest Rate Mode or the maturity of the Bonds.

"*Dutch Auction Rate*" means, with respect to the 2006 Series B Bonds, the rate of interest to be borne by the Bonds during each Dutch Auction Rate Period determined in accordance with the 2006 Series B Indenture.

"*Dutch Auction Rate Period*" means, with respect to the 2006 Series B Bonds, each period during which the 2006 Series B Bonds bear interest at a Dutch Auction Rate.

"*Flexible Rate*" means the Interest Rate Mode for the Bonds in which the interest rate for each Bond is determined with respect to such Bond during each Flexible Rate Period applicable to that Bond, as provided in the Indenture.

"*Flexible Rate Period*" means with respect to any Bond, each period (which may be from one day to 270 days, or such lower maximum number of days as is then permitted under the Indenture) determined for such Bond, as provided in the Indenture.

"*Initial Credit Facility*" means the irrevocable direct pay letter of credit issued by the Initial Credit Facility Issuer to the Trustee with respect to the Bonds on the Conversion Date.

"*Initial Credit Facility Issuer*" means Commerzbank AG, New York.

"*Interest Payment Date*" means (i) if the Interest Rate Mode is the Daily Rate or the Weekly Rate, the first Business Day of each calendar month, (ii) if the Interest Rate Mode is the Flexible Rate, for each Bond the last day of each Flexible Rate Period for such Bond (or if such day is not a Business Day, the next succeeding Business Day), (iii) if the Interest Rate Mode is the Semi-Annual Rate, the Annual Rate or the Long Term Rate, June 1 and December 1, and, in the case of the Long Term Rate, also the Conversion Date or the effective date of a change to a new Long Term Rate Period, (iv) with respect to the 2006 Series B Bonds, if the Interest Rate Mode is the Dutch Auction Rate Period, the dates determined in accordance with the terms of the Indenture or (v) with respect to any Bond, the Conversion Date (including the date of a failed Conversion) or the effective date of a change to a new Long Term Rate Period for such Bond. In any case, the final Interest Payment Date will be the maturity date of the Bonds.

"*Interest Period*" means for all Bonds (or for any Bond if the Interest Rate Mode is the Flexible Rate) the period from and including each Interest Payment Date to and including the day immediately preceding the next Interest Payment Date, provided, however that the first Interest Period for the Bonds will begin on (and include) the date of issuance of the Bonds and the final Interest Period will end on September 30, 2034, with respect to the 2006 Series B Bonds, or January 31, 2032, with respect to the 2008 Series A Bonds.

"*Interest Rate Mode*" means the Flexible Rate, the Daily Rate, the Weekly Rate, the Semi-Annual Rate, the Annual Rate, the Long Term Rate for each series of the Bonds and, with respect to the 2006 Series B Bonds, the Dutch Auction Rate.

"*Long Term Rate Period*" means any period established by the Company as hereinafter set forth under "— Determination of Interest Rates for Interest Rate Modes — Long Term Rates and Long Term Rate Periods" and beginning on, and including, the Conversion Date to the Long Term Rate and ending on, and including, the day preceding the last Interest Payment Date for such period and, thereafter, each successive period of the same duration as the Long Term Rate Period previously established until the day preceding the earliest of the change to a different Long Term Rate Period, the Conversion to a different Interest Rate Mode or the maturity of the Bonds.

"*Maximum Rate*" means the lesser of (i) the maximum interest rate permitted by applicable law or (ii) 15%.

"*Prevailing Market Conditions*" means, without limitation, the following factors: existing short-term or long-term market rates for securities, the interest on which is excluded from gross income for federal income tax purposes; indexes of such short-term or long-term rates and the existing market supply and demand for securities bearing such short-term or long-term rates; existing yield curves for short-term or long-term securities for obligations of credit quality comparable to the Bonds, the interest on which is excluded from gross income for federal income tax purposes; general economic conditions; industry economic and financial conditions that may affect or be relevant to the Bonds; and such other facts, circumstances and conditions as the Remarketing Agent, in its sole discretion, determines to be relevant.

"*Purchase Date*" means any date on which Bonds are to be purchased on the demand of the registered owners thereof or are subject to mandatory purchase as described in the Indenture.

"*Reimbursement Agreement*" means the Reimbursement Agreement, to be dated as of December 19, 2008, between the Company and the Initial Credit Facility Issuer, as the same may be amended from time to time, and any other agreement between the Company and a Credit Facility Issuer, setting forth the obligations of the Company to such Credit Facility Issuer arising out of any payments under such Credit Facility and which provides that it will be deemed to be a Reimbursement Agreement for the purpose of the Indenture.

"*Semi-Annual Rate Period*" means any period beginning on, and including, the Conversion Date to the Semi-Annual Rate, and ending on, and including, the day preceding the first Interest Payment Date thereafter and each successive six-month period thereafter beginning on and including an Interest Payment Date and ending on and including the day next preceding the next Interest Payment Date until the day preceding the earlier of the Conversion to a different Interest Rate Mode or the maturity of the Bonds.

"*Weekly Rate Period*" means, (i) with respect to the 2006 Series B Bonds, the period beginning on, and including the Conversion Date to the Weekly Rate, and ending on, and including, the next Thursday, and thereafter the period beginning on, and including any Friday and ending on, and including, the earliest of the next Thursday, the day preceding the Conversion to a different Interest Rate Mode or the maturity of the Bonds, and (ii) with respect to the 2008 Series A Bonds, the period beginning on, and including, the Conversion Date to the Weekly Rate, and ending on, and including, the next Wednesday, and thereafter the period beginning on, and including, any Thursday and ending on, and including, the earliest of the next Wednesday, the day preceding the Conversion to a different Interest Rate Mode or the maturity of the Bonds.

Summary of Certain Provisions of the Bonds

The following table summarizes, for each of the permitted Interest Rate Modes (except the Dutch Auction Rate with respect to the 2006 Series B Bonds): the dates on which interest will be paid (*Interest Payment Dates*); the dates on which each interest rate will be determined (*Interest Rate Determination Dates*); the period of time (*Interest Rate Periods*) each interest rate will be in effect (provided that the initial Interest Rate Period for each Interest Rate Mode may begin on a different date from that specified, which date will be the Conversion Date or the date of a change in the Long Term Rate, as applicable); the dates on which registered owners may tender their Bonds for purchase to the Tender Agent and the notice requirements therefor (provided that while the Bonds are held in book-entry-only form, all notices of tender for purchase will be given by Beneficial Owners in the manner described below under "Purchases of Bonds on Demand of Owner — Notice Required for Purchases") (*Purchase on Demand of Owner; Required Notice*); the dates on which Bonds are subject to mandatory tender for purchase (*Mandatory Purchase Dates*); the redemption provisions applicable to the Bonds (*Redemption*); the notice requirements for redemption and mandatory tender for purchase (*Notices of Redemption and Mandatory Purchases*); and the manner by which registered owners will receive payments of principal, interest, redemption price and purchase price (*Manner of Payment*). All times stated are New York City time. Provisions relating to the Bonds while they bear interest at a Dutch Auction Rate, with respect to the 2006 Series B Bonds, will be determined in accordance with auction procedures established at the time of conversion to the Dutch Auction Rate.

	FLEXIBLE RATE	DAILY RATE	WEEKLY RATE
Interest Payment Dates	With respect to any Bond, the last day of each Flexible Rate Period (or if such day is not a Business Day, the next succeeding Business Day).	The first Business Day of each calendar month.	The first Business Day of each calendar month.
Interest Rate Determination Dates	For each Bond, not later than 12:00 noon on the first day of each Flexible Rate Period for such Bond.	Not later than 9:30 a.m. on each Business Day.	Not later than 4:00 p.m. on the day preceding the first day of each Weekly Rate Period or, if not a Business Day, on the next preceding Business Day.
Interest Rate Periods	For each Bond, each Flexible Rate Period will be of a duration designated by the Remarketing Agent of one day to 270 days (or lower maximum number as specified in the Indenture); must end on a day immediately preceding a Business Day.	From and including each Business Day to but not including the next Business Day.	From and including each Friday to and including the following Thursday for the 2006 Series B Bonds. From and including each Thursday to and including the following Wednesday for the 2008 Series A Bonds.
Purchase on Demand of Owner; Required Notice*	No purchase on demand of the owner.	Any Business Day; by written or telephonic notice, promptly, with respect to the 2006 Series B Bonds, or immediately, with respect to the 2008 Series A Bonds, confirmed in writing, to the Tender Agent by 10:00 a.m. on such Business Day.	Any Business Day; by written notice to the Tender Agent not later than 5:00 p.m. on a Business Day at least seven days prior to the Purchase Date.
Mandatory Purchase Dates	Any Conversion Date; and with respect to each Bond, on each Interest Payment Date for such Bond; and upon delivery, cancellation, substitution, extension, termination or expiration of any Credit Facility or replacement with Alternate Credit Facility.	Any Conversion Date; and upon delivery, cancellation, substitution, extension, termination or expiration of any Credit Facility or replacement with Alternate Credit Facility	Any Conversion Date; and upon delivery, cancellation, substitution, extension, termination or expiration of any Credit Facility or replacement with Alternate Credit Facility.
Redemption	Optional at par on any Interest Payment Date; Extraordinary Optional and Mandatory at par, on any Business Day (other than extraordinary optional redemption as a result of damage, destruction or condemnation which will be on an Interest Payment Date).	Optional, Extraordinary Optional and Mandatory at par on any Business Day.	Optional, Extraordinary Optional and Mandatory at par on any Business Day.
Notices of Conversion, Redemption and Mandatory Purchases*	Not fewer than 15 days (30 days notice of Conversion to the Semi-Annual, Annual or Long Term Rate) or greater than 45 days. No notice of mandatory purchase following end of each Flexible Rate Period.	Not fewer than 15 days (30 days notice of Conversion to the Semi-Annual, Annual or Long Term Rate) or greater than 45 days.	Not fewer than 15 days (30 days notice of Conversion to the Semi-Annual, Annual or Long Term Rate) or greater than 45 days.
Manner of Payment*	Principal or redemption price upon surrender of the Bond to the Paying Agent; purchase price upon surrender of the Bond to the Tender Agent.	Principal or redemption price upon surrender of the Bond to the Paying Agent; purchase price upon surrender of the Bond to the Tender Agent.	Principal or redemption price upon surrender of the Bond to the Paying Agent; purchase price upon surrender of the Bond to the Tender Agent.

* So long as DTC or its nominee is the registered owner of the Bonds, notices of redemption and mandatory purchases shall be sent to Cede & Co., payments of principal, redemption and purchase price of and interest on the Bonds will be paid through the facilities of DTC and notices of mandatory purchase may be given not less than five days prior to the Purchase Date. See "— Book-Entry-Only System" below.

	SEMI-ANNUAL	ANNUAL	LONG TERM
Interest Payment Date	Each June 1 and December 1.	Each June 1 and December 1.	Each June 1 and December 1, any Conversion Date; and the effective date of any change to a new Long Term Rate Period.
Interest Rate Determination Dates	Not later than 2:00 p.m. on the Business Day preceding the first day of the Semi-Annual Rate Period.	Not later than 12:00 noon on the Business Day preceding the first day of the Annual Rate Period.	Not later than 12:00 noon on the Business Day preceding the first day of the Long Term Rate Period.
Interest Rate Periods	Each six-month period from and including each June 1 and December 1 to and including the day preceding the next Interest Payment Date.	Each period from and including the Conversion Date to the Annual Rate to and including the day immediately preceding the second Interest Payment Date thereafter and each successive twelve month period thereafter.	Each period designated by the Company of more than one year in duration and which is an integral multiple of six months, from and including the first day of such period (June 1 and December 1) to and including the day immediately preceding the last Interest Payment Date for that period.
Purchase on Demand of Owner; Required Notice*	On any Interest Payment Date; by written notice to the Tender Agent on any Business Day not later than the fifteenth day prior to the Purchase Date.	On the final Interest Payment Date for the Annual Rate Period; by written notice to the Tender Agent on any Business Day not later than the fifteenth day prior to the Purchase Date.	On the final Interest Payment Date for the Long Term Rate Period; by written notice to the Tender Agent on a Business Day not later than the fifteenth day prior to the Purchase Date.
Mandatory Purchase Dates	Any Conversion Date; the first Business Day after the end of each Semi-Annual Rate Period; and upon delivery, cancellation, substitution, extension, termination or expiration of any Credit Facility or replacement with Alternate Credit Facility.	Any Conversion Date; the first Business Day after the end of each Annual Rate Period; and upon delivery, cancellation, substitution, extension, termination or expiration of any Credit Facility or replacement with Alternate Credit Facility.	Any Conversion Date; the first Business Day after the end of each Long Term Rate Period; the effective date of a change of Long Term Rate Period; and upon delivery, cancellation, substitution, extension, termination or expiration of any Credit Facility or replacement with Alternate Credit Facility.
Redemption	Optional at par on any Interest Payment Date; Extraordinary Optional and Mandatory at par, on any Business Day (other than extraordinary optional redemption as a result of damage, destruction or condemnation which will be on an Interest Payment Date).	Optional at par on the final Interest Payment Date; Extraordinary Optional and Mandatory at par, on any Business Day.	Optional at times and prices dependent on the length of the Long Term Rate Period; Extraordinary Optional and Mandatory at par, on any Business Day.
Notices of Conversion, Redemption and Mandatory Purchases*	Not fewer than 15 days (30 days for notice of Conversion or redemption) or greater than 45 days.	Not fewer than 15 days (30 days for notice of Conversion or redemption) or greater than 45 days.	Not fewer than 15 days (30 days for notice of Conversion or redemption) or greater than 45 days.
Manner of Payment*	Principal or redemption price upon surrender of the Bond to the Paying Agent; interest by check mailed to the registered owners or, upon request of registered owner, of $1,000,000 or more of an individual issue of Bonds, in immediately available funds; purchase price upon surrender of the Bond to the Tender Agent.	Principal or redemption price upon surrender of the Bond to the Paying Agent; interest by check mailed to the registered owners or, upon request of registered owner, of $1,000,000 or more of an individual issue of Bonds, in immediately available funds; purchase price upon surrender of the Bond to the Tender Agent.	Principal or redemption price upon surrender of the Bond to the Paying Agent; interest by check mailed to the registered owners or, upon request of registered owner, of $1,000,000 or more of an individual issue of Bonds, in immediately available funds; purchase price upon surrender of the Bond to the Tender Agent.

* So long as DTC or its nominee is the registered owner of the Bonds, notices of redemption and mandatory purchases shall be sent to Cede & Co., payments of principal, redemption and purchase price of and interest on the Bonds will be paid through the facilities of DTC and notices of mandatory purchase may be given not less than five days prior to the Purchase Date. See "— Book-Entry-Only System" below.

Determination of Interest Rates for Interest Rate Modes

Daily Rate. If the Interest Rate Mode for the Bonds is the Daily Rate, the interest rate on the Bonds for any Business Day will be the rate established by the Remarketing Agent no later than 9:30 a.m. (New York City time) on each Business Day as the minimum rate of interest necessary, in the judgment of the Remarketing Agent taking into account then Prevailing Market Conditions, to enable the Remarketing Agent to sell the Bonds on such Business Day at a price equal to the principal amount thereof, plus accrued interest, if any, thereon. For any day which is not a Business Day or if the Remarketing Agent does not give notice of a change in the interest rate, the interest rate on the Bonds will be the interest rate in effect for the immediately preceding Business Day.

Weekly Rate. If the Interest Rate Mode for the Bonds is the Weekly Rate, the interest rate on the Bonds for a particular Weekly Rate Period will be the rate established by the Remarketing Agent no later than 4:00 p.m. (New York City time) on the day preceding such Weekly Rate Period or, if such day is not a Business Day, on the next preceding Business Day, as the minimum rate of interest necessary, in the judgment of the Remarketing Agent taking into account then Prevailing Market Conditions, to enable the Remarketing Agent to sell the Bonds on such first day at a price equal to the principal amount thereof, plus accrued interest, if any, thereon.

Flexible Rates and Flexible Rate Periods. If the Interest Rate Mode for the Bonds is the Flexible Rate, the interest rate on a Bond for a specific Flexible Rate Period will be the rate established by the Remarketing Agent no later than 12:00 noon (New York City time) on the first day of that Flexible Rate Period as the minimum rate of interest necessary, in the judgment of the Remarketing Agent taking into account then Prevailing Market Conditions, to enable the Remarketing Agent to sell such Bond on that day at a price equal to the principal amount thereof. Each Flexible Rate Period applicable for a Bond will be determined separately by the Remarketing Agent on or prior to the first day of such Flexible Rate Period as being the Flexible Rate Period permitted under the Indenture which, in the judgment of the Remarketing Agent, taking into account then Prevailing Market Conditions, will, with respect to such Bond, ultimately produce the lowest overall interest cost on the Bonds while the Interest Rate Mode for the Bonds is the Flexible Rate. Each Flexible Rate Period will be from one day to 270 days in length and will end on a day preceding a Business Day. If the Remarketing Agent fails to set the length of a Flexible Rate Period for any Bond, a new Flexible Rate Period lasting to, but not including, the next Business Day (or until the earlier Conversion or maturity of the Bonds) will be established automatically in accordance with the Indenture.

Semi-Annual Rate. If the Interest Rate Mode for the Bonds is the Semi-Annual Rate, the interest rate on the Bonds for a particular Semi-Annual Rate Period will be the rate established by the Remarketing Agent no later than 2:00 p.m. (New York City time) on the Business Day immediately preceding the first day of such Semi-Annual Rate Period as the minimum rate of interest necessary, in the judgment of the Remarketing Agent taking into account then Prevailing Market Conditions, to enable the Remarketing Agent to sell the Bonds on such first day at a price equal to the principal amount thereof.

Annual Rate. If the Interest Rate Mode for the Bonds is the Annual Rate, the interest rate on the Bonds for a particular Annual Rate Period will be the rate of interest established by the Remarketing Agent no later than 12:00 noon (New York City time) on the Business Day preceding the first day of such Annual Rate Period as the minimum rate of interest necessary, in the judgment of the Remarketing Agent taking into account then Prevailing Market Conditions, to enable the Remarketing Agent to sell the Bonds on such first day at a price equal to the principal amount thereof.

Dutch Auction Rate. With respect to the 2006 Series B Bonds, if the Interest Rate Mode for the Bonds is the Auction Rate, the interest rate on the Bonds for a particular Auction Rate Period will be the rate established in accordance with the procedures set forth in the Indenture.

Long Term Rates and Long Term Rate Periods. If the Interest Rate Mode for the Bonds is the Long Term Rate, the interest rate on the Bonds for a particular Long Term Rate Period will be the rate established by the Remarketing Agent no later than 12:00 noon (New York City time) on the Business Day preceding the first day of such Long Term Rate Period as the minimum rate of interest necessary, in the judgment of the Remarketing Agent taking into account then Prevailing Market Conditions, to enable the Remarketing Agent to sell the Bonds on such first day at a price equal to the principal amount thereof. The Company will establish the duration of the Long Term Rate Period at the time that it directs the Conversion of the Interest Rate Mode to the Long Term Rate, and thereafter each successive Long Term Rate Period will be the same as the Long Term Rate Period so established by the Company until a different Long Term Rate Period is specified by the Company in accordance with the Indenture (in which case the duration of that Long Term Rate Period will control succeeding Long Term Rate Periods), subject in all cases to the occurrence of a Conversion Date or the maturity of the Bonds. Each Long Term Rate Period will be more than one year in duration, will be for a period which is an integral multiple of six months and will end on the day next preceding an Interest Payment Date; provided that if a Long Term Rate Period commences on a date other than a June 1 or December 1, such Long Term Rate Period may be for a period which is not an integral multiple of six months but will be of a duration as close as possible to (but not in excess of) such Long Term Rate Period established by the Company and will terminate on a day preceding an Interest Payment Date, and each successive Long Term Rate Period thereafter will be for the full period established by the Company until a different Long Term Rate Period is specified by the Company in accordance with the Indenture or until the occurrence of a Conversion Date or the maturity of the Bonds; provided further that no Long Term Rate Period will extend beyond the final maturity date of the Bonds.

Change of Long Term Rate Period. The Company may change from one Long Term Rate Period to another Long Term Rate Period on any Business Day on which the Bonds are subject to optional redemption as described under "— Redemptions — Optional Redemption" below upon notice from the Bond Registrar to the owners of Bonds as described below. With any notice of such change, the Company must also deliver an opinion of Bond Counsel stating that such change is authorized or permitted by the Act and is authorized by the Indenture and will not adversely affect the exclusion from gross income of interest on the Bonds for federal income tax purposes. Notwithstanding the foregoing, the Long Term Rate Period will not be changed to a new Long Term Rate Period if (A) the Remarketing Agent has not determined the interest rate for the new Long Term Rate Period in accordance with the terms of the Indenture or

(B) the Bond Registrar receives written notice from Bond Counsel prior to the effective date of the change to the effect that the opinion of such Bond Counsel required under the Indenture has been rescinded. Upon the occurrence of any of the events described in the preceding sentence, the Bonds will bear interest at the Weekly Rate commencing on the date which would have been the effective date of the proposed change of Long Term Rate Period, subject to the provisions described under "— Conversion of Interest Rate Modes — Cancellation of Conversion of Interest Rate Mode" below.

Notice to Owners of Change of Long Term Rate Period. The Bond Registrar will notify each registered owner of the change of Long Term Rate Period by first class mail at least 30 days in the case of a change in the Long Term Rate Period but not more than 45 days before each effective date of a change in the Long Term Rate Period. The notice will state those matters required to be set forth therein under the Indenture.

Failure to Determine Rate. If for any reason the interest rate for a Bond is not determined by the Remarketing Agent, except as described above under "— Change of Long Term Rate Period" and below under "— Conversion of Interest Rate Modes — Cancellation of Conversion of Interest Rate Mode," the interest rate for such Bond for the next succeeding interest rate period will be the interest rate in effect for such Bond for the preceding interest rate period and, pursuant to the terms of the Indenture, there will be no change in the then applicable Long Term Rate Period or any Conversion from the then applicable Interest Rate Mode. Notwithstanding the foregoing, if for any reason the interest rate for a Bond bearing interest at a Flexible Rate is not determined by the Remarketing Agent, the interest rate for such Bond for the next succeeding Interest Period will be equal to The Bond Market Association Municipal Swap Index™ (the "Municipal Index") as defined in the Indenture, and the Interest Period for such Bond will extend through the day preceding the next Business Day, until the Trustee is notified of a new Flexible Rate and Flexible Rate Period determined for such Bond by the Remarketing Agent.

Conversion of Interest Rate Modes

Method of Conversion. The Interest Rate Mode for the Bonds is subject to Conversion from time to time, in whole but not in part, on the dates specified below under "— Limitations on Conversion," at the option of the Company, upon notice from the Bond Registrar to the registered owners of the Bonds, as described below. With any notice of Conversion, the Company must also deliver to the Bond Registrar and the Credit Facility Issuer an opinion of Bond Counsel stating that such Conversion is authorized or permitted by the Act and is authorized by the Indenture and will not adversely affect the exclusion from gross income of interest on the Bonds for federal income tax purposes, other than a Conversion from the Daily Rate Period to the Weekly Rate Period or from the Weekly Rate Period to the Daily Rate Period.

Conditions Precedent to Conversions. The following conditions are applicable to Conversions of the Bonds:

(a) any Credit Facility to be held by the Trustee after the Conversion Date must be sufficient to cover the principal of and accrued interest on the outstanding Bonds for the maximum Interest Period permitted for that particular Interest Rate Mode plus 10 days at the maximum interest rate, and if a Credit Facility is to be held by the Trustee after the Conversion of the Bonds to a Long Term Rate Period, that Credit Facility must also extend for the entire Long Term Rate Period plus 10 days at the maximum interest rate; and

(b) if a Credit Facility is then in effect and the purchase price of the Bonds under the Indenture includes any premium, the Trustee will be entitled to draw on that Credit Facility in an aggregate amount sufficient to pay the applicable purchase price (including such premium) or, in the alternative, available moneys will be available in the necessary amount and are applied to the payment of such premium.

Limitations on Conversion. Any Conversion of the Interest Rate Mode for the Bonds must be in compliance with the following conditions: (i) the Conversion Date must be a date on which the Bonds are subject to optional redemption (see "— Redemptions — Optional Redemption" below); provided that any Conversion from the Daily Rate Period to a Weekly Rate Period or from the Weekly Rate Period to the Daily Rate Period must be on a Friday, with respect to the 2006 Series B Bonds, or Thursday, with respect to the 2008 Series A Bonds, and, with respect to the 2006 Series B Bonds, if the Conversion is to or from a Dutch Auction Rate Period, the Conversion Date must be the last Interest Payment Date in respect of that Dutch Auction Rate Period; (ii) if the proposed Conversion Date would not be an Interest Payment Date but for the Conversion, the Conversion Date must be a Business Day; (iii) if the Conversion is from the Flexible Rate, (a) the Conversion Date may be no earlier than the latest Interest Payment Date established prior to the giving of notice to the Remarketing Agent of such proposed Conversion and (b) no further Interest Payment Date may be established while the Interest Rate Mode is then the Flexible Rate if such Interest Payment Date would occur after the effective date of that Conversion; and (iv) after a determination is made requiring mandatory redemption of all Bonds pursuant to the Indenture (see "— Redemptions" below), no change in the Interest Rate Mode may be made prior to such mandatory redemption.

Notice to Owners of Conversion of Interest Rate Mode. The Bond Registrar will notify each registered owner of the Conversion by first class mail at least 15 days (30 days in the case of Conversion from or to the Semi-Annual Rate, the Annual Rate, a Long Term Rate or, with respect to the 2006 Series B Bonds, a Dutch Auction Rate) but not more than 45 days before the Conversion Date. The notice will state those matters required to be set forth therein under the Indenture.

Cancellation of Conversion of Interest Rate Mode. Notwithstanding the foregoing, no Conversion will occur if (i) the Remarketing Agent has not determined the initial interest rate for the new Interest Rate Mode in accordance with the terms of the Indenture, (ii) the Bonds that are to be purchased are not remarketed or sold by the Remarketing Agent or (iii) the Bond Registrar receives written notice from Bond Counsel prior to the opening of business on the effective date of Conversion to the effect that the opinion of such Bond Counsel required under the Indenture has been rescinded. If such Conversion fails to occur, such Bonds will automatically be converted to the Weekly Rate (with the first period adjusted in length so that the last day of such period will be a Wednesday) at the rate determined by the Remarketing Agent on the failed Conversion Date or, with respect to the 2006 Series B Bonds that bear interest at a Dutch Auction Rate, such Bonds will remain in such Interest Rate Mode; provided, that there must be delivered to the Issuer, the Trustee, the Bond Registrar, the Tender Agent, the Company, the Credit Facility Issuer and the Remarketing Agent an opinion of Bond Counsel to the effect that determining the interest rate to be borne by the Bonds at a Weekly Rate is authorized or permitted by the Act and is authorized under the Indenture and will not adversely affect the exclusion from gross income of interest on the Bonds for federal income tax purposes. If such opinion is not delivered on the failed Conversion Date, the Bonds will bear interest for a Rate Period of the same type and of substantially the same length as the Rate Period in effect prior to the failed Conversion Date at a rate of interest determined by the Remarketing Agent on the failed Conversion Date (or if shorter, the Rate Period ending on the day before the maturity date, with respect to the 2006 Series B Bonds); provided that if the Bonds then bear interest at the Long Term Rate, and if such opinion is not delivered on the date which would have been the effective date of a new Long Term Rate Period, the Bonds will bear interest at the Annual Rate, commencing on such date, at an Annual Rate determined by the Remarketing Agent on such date. If the proposed Conversion of Bonds fails as described herein, any mandatory purchase of such Bonds will remain effective.

Purchases of Bonds on Demand of Owner

If the Bonds are in the book-entry-only system, demands for purchase may be made by Beneficial Owners only through such Beneficial Owner's Direct Participant (as defined under the caption "— Book-Entry-Only System" below). If the Bonds are in certificated form, demands for purchase may be made only by registered owners. When the Interest Rate Mode is the Dutch Auction Rate, the Bonds are not subject to purchase on demand of the owners thereof.

Daily Rate. If the Interest Rate Mode for the Bonds is the Daily Rate, any Bond will be purchased on the demand of the registered owner thereof on any Business Day during a Daily Rate Period at a purchase price equal to the principal amount thereof plus accrued interest, if any, to the Purchase Date upon written notice or telephonic notice (to be immediately confirmed in writing) to the Tender Agent at its principal office not later than 10:00 a.m. (New York City time) on such Business Day.

Weekly Rate. If the Interest Rate Mode for the Bonds is the Weekly Rate, any Bond will be purchased on the demand of the registered owner thereof on any Business Day during a Weekly Rate Period at a purchase price equal to the principal amount thereof plus accrued interest, if any, to the Purchase Date upon written notice to the Tender Agent at its principal office at or before 5:00 p.m. (New York City time) on a Business Day not later than the seventh day prior to the Purchase Date.

Semi-Annual Rate. If the Interest Rate Mode for the Bonds is the Semi-Annual Rate, any Bond will be purchased on the demand of the registered owner thereof on any Interest Payment Date for a Semi-Annual Rate Period at a purchase price equal to the principal amount thereof upon written notice to the Tender Agent at its principal office on a Business Day not later than the fifteenth day prior to such Purchase Date.

Annual Rate. If the Interest Rate Mode for the Bonds is the Annual Rate, any Bond will be purchased on the demand of the registered owner thereof on the final Interest Payment Date for such Annual Rate Period at a purchase price equal to the principal amount thereof upon written notice to the Tender Agent at its principal office on a Business Day not later than the fifteenth day prior to such Purchase Date.

Long Term Rate. If the Interest Rate Mode for the Bonds is the Long Term Rate, any Bond will be purchased on the demand of the registered owner thereof on the final Interest Payment Date for such Long Term Rate Period (unless such date is the final maturity date) at a purchase price equal to the principal amount thereof upon written notice to the Tender Agent at its principal office on a Business Day not later than the fifteenth day prior to such Purchase Date.

Limitations on Purchases on Demand of Owner. Notwithstanding the foregoing, there will be no purchase of (a) a portion of any Bond unless the portion to be purchased and the portion to be retained each will be in an authorized denomination or (b) any Bond upon the demand of the registered owner if an Event of Default under the Indenture with respect to the payment of principal of, interest on, or purchase price of, the Bonds has occurred and is continuing. Also, if the Interest Rate Mode for the Bonds is the Flexible Rate, the Bonds will not be subject to purchase on the demand of the registered owners thereof, but each Bond will be subject to mandatory purchase on each Conversion Date and on the Interest Payment Date with respect to such Bond, as described below under the caption "— Mandatory Purchases of Bonds."

Notice Required for Purchases. Any written notice delivered to the Tender Agent by an owner demanding the purchase of Bonds must (A) be delivered by the time and dates specified above, (B) state the number and principal amount (or portion thereof) of such Bond to be purchased, (C) state the Purchase Date on which such Bond is to be purchased, (D) irrevocably request such purchase and state that the owner agrees to deliver such Bond, duly endorsed in blank for transfer, with all signatures guaranteed, to the Tender Agent at or prior to 11:00 a.m. (1:00 p.m. if a tender during a Daily Rate Period and 12:00 noon if a tender during a Weekly Rate Period) (New York City time) on such Purchase Date.

Mandatory Purchases of Bonds

Mandatory Purchase on Conversion Dates or Change by the Company in Long Term Rate Period. The Bonds will be subject to mandatory purchase at a purchase price equal to the principal amount thereof, plus accrued interest, if any, to the Purchase Date, plus, if the Interest Rate Mode is the Long Term Rate, the redemption premium, if any, which would be payable as described under "— Redemptions — Optional Redemption" below, if the Bonds were redeemed (A) on the Purchase Date, (B) on each Conversion Date and (C) on the effective date of any change by the Company of the Long Term Rate Period. Such tender and purchase will be required even if the change in Long Term Rate Period or the Conversion is canceled pursuant to the Indenture.

Mandatory Purchase on Each Interest Payment Date for Flexible Rate Period. Whenever the Interest Rate Mode for the Bonds is the Flexible Rate, each Bond will be subject to mandatory purchase at a purchase price equal to the principal amount thereof, without premium, plus accrued interest, if any, to the Purchase Date, on each Interest Payment Date that interest on such Bond is payable at an interest rate determined for the Flexible Rate. Owners of Bonds will receive no notice of such mandatory purchase.

Mandatory Purchase on Day after End of the Semi-Annual Rate Period, the Annual Rate Period or the Long Term Rate Period. Whenever the Interest Rate Mode for the Bonds is the Semi-Annual Rate, the Annual Rate or the Long Term Rate, such Bonds will be subject to mandatory purchase on the Business Day following the end of each Semi-Annual Rate Period, Annual Rate Period or Long Term Rate Period, as the case may be, for such Bond at a purchase price equal to the principal amount thereof plus accrued interest, if any, to such date.

Mandatory Purchase upon Delivery, Cancellation, Substitution, Extension, Termination or Expiration of Any Credit Facility or Replacement with an Alternate Credit Facility. If, at the option of the Company, a Credit Facility (other than the initial Letter of Credit) is delivered with respect to the Bonds subsequent to the Reoffering Date, the Bonds will be subject to mandatory tender for purchase at a purchase price equal to 100% of the principal amount thereof, plus accrued interest, if any, to the Purchase Date on the date of the delivery of the Credit Facility. In addition, if the Bonds are secured by a Credit Facility, the Bonds will be subject to mandatory tender for purchase at a purchase price equal to 100% of the principal amount thereof, plus accrued interest, if any, (A) on the Interest Payment Date at least five days prior to the date of the cancellation of or the expiration of the term of the then current Credit Facility and (B) on the Interest Payment Date on which a Credit Facility is replaced with an Alternate Credit Facility.

Notice to Owners of Mandatory Purchases. Notice to owners of a mandatory purchase of Bonds (except for mandatory purchase on each Interest Payment Date for Flexible Rate Periods) will be given by the Bond Registrar, by first class mail at least 15 days but not more than 45 days before the Purchase Date; provided, however, as an alternative to the foregoing, if DTC or its nominee is the registered owner of the Bonds, notice may be given to DTC not less than five days before the Purchase Date. The notice of mandatory purchase will state those matters required to be set forth therein under the Indenture. No notice of mandatory purchase will be given in connection with a mandatory purchase on an Interest Payment Date for a Flexible Rate Period.

Remarketing and Purchase of Bonds

The Indenture provides that, subject to the terms of a Remarketing Agreement with the Company, the Remarketing Agent will use its reasonable best efforts to offer for sale Bonds purchased upon demand of the owners thereof and, unless otherwise instructed by the Company and with the consent of any Credit Facility Issuer, upon mandatory purchase, provided that Bonds will not be remarketed upon the occurrence and continuance of certain Events of Default under the Indenture, except in the sole discretion of the Remarketing Agent. Each such sale will be at a price equal to the principal amount thereof, plus interest accrued to the date of sale. The Remarketing Agent, the Trustee, the Paying Agent, the Bond Registrar or the Tender Agent each may purchase any Bonds offered for sale for its own account.

On each date Bonds are to be purchased pursuant to optional or mandatory purchase under the Indenture, such Bonds will be purchased from the following sources in the order of priority indicated, provided that funds derived from clause (c) may not be combined with the funds derived from clauses (a) or (b) to purchase any Bonds:

(a) proceeds of the remarketing of such Bonds to persons other than the Company, its affiliates or the Issuer and furnished to the Tender Agent by the Remarketing Agent and deposited directly into, and held in, the Remarketing Proceeds Subaccount of the Purchase Fund established with the Tender Agent under the Indenture;

(b) proceeds of the Credit Facility, if any, furnished by the Trustee, as Tender Agent, and deposited by the Tender Agent directly into, and held in, the Credit Facility Subaccount of the Purchase Fund; and

(c) moneys paid by the Company (including the proceeds of the remarketing of the Bonds to the Company, its affiliates or the Issuer) to pay the purchase price to the Tender Agent.

If there is no Credit Facility in operation to secure the Bonds, any Bonds will be purchased with any moneys made available by the Company, including proceeds from the remarketing of the Bonds.

Payment of Purchase Price

When a book-entry-only system is not in effect, payment of the purchase price of any Bond will be payable (and delivery of a replacement Bond in exchange for the portion of any Bond not purchased if such Bond is purchased in part will be made) on the Purchase Date upon delivery of such Bond to the Tender Agent on such Purchase Date; provided that such Bond must be delivered to the Tender Agent: (i) at or prior to 12:00 noon (New York City time), in the case of Bonds delivered for purchase during a Weekly Rate Period or Flexible Rate Period, (ii) at or prior to 1:00 p.m. (New York City time), in the case of Bonds delivered for purchase during a Daily Rate Period or (iii) at or prior to 11:00 a.m. (New York City time), in the case of Bonds delivered for purchase during a Semi-Annual Rate Period, Annual Rate Period or Long Term Rate Period. If the date of such purchase is not a Business Day, the purchase price will be payable on the next succeeding Business Day.

Any Bond delivered for payment of the purchase price must be accompanied by an instrument of transfer thereof in form satisfactory to the Tender Agent executed in blank by the registered owner thereof and with all signatures guaranteed. The Tender Agent may refuse to accept delivery of any Bond for which an instrument of transfer satisfactory to it has not been provided and has no obligation to pay the purchase price of such Bond until a satisfactory instrument is delivered.

If the registered owner of any Bond (or portion thereof) that is subject to purchase pursuant to the Indenture fails to deliver such Bond with an appropriate instrument of transfer to the Tender Agent for purchase on the Purchase Date, and if the Tender Agent is in receipt of the purchase price therefor, such Bond (or portion thereof) nevertheless will be deemed purchased on the Purchase Date thereof. Any owner who so fails to deliver such Bond for purchase on (or before) the Purchase Date will have no further rights thereunder, except the right to receive the purchase price thereof from those moneys deposited with the Tender Agent in the Purchase Fund pursuant to the Indenture upon presentation and surrender of such Bond to the Tender Agent properly endorsed for transfer in blank with all signatures guaranteed.

When a book-entry-only system is in effect, the requirement for physical delivery of the Bonds will be deemed satisfied when the ownership rights in the Bonds are transferred by Direct Participants on the records of DTC to the participant account of the Tender Agent.

Redemptions

Optional Redemption.

(i) Whenever the Interest Rate Mode for the Bonds is the Daily Rate or the Weekly Rate, the Bonds will be subject to redemption at the option of the Issuer, upon the written direction of the Company, in whole or in part, at a redemption price of 100% of the principal amount thereof, plus interest accrued, if any, to the redemption date, on any Business Day.

(ii) Whenever the Interest Rate Mode for a Bond is the Flexible Rate, such Bond will be subject to redemption at the option of the Issuer, upon the written direction of the Company, in whole or in part, at a redemption price of 100% of the principal amount thereof, plus accrued interest, if any, to the redemption date with respect to the 2008 Series A Bonds, on any Interest Payment Date for that Bond.

(iii) Whenever the Interest Rate Mode for the Bonds is the Semi-Annual Rate, the Bonds will be subject to redemption at the option of the Issuer, upon the written direction of the Company, in whole or in part, at a redemption price of 100% of the principal amount thereof on any Interest Payment Date for each Semi-Annual Rate Period.

(iv) Whenever the Interest Rate Mode for the Bonds is the Annual Rate, the Bonds will be subject to redemption at the option of the Issuer, upon the written direction of the Company, in whole or in part, at a redemption price of 100% of the principal amount thereof on the final Interest Payment Date for each Annual Rate Period.

(v) With respect to the 2006 Series B Bonds, whenever the Interest Rate Mode for the Bonds is the Dutch Auction Rate, the Bonds will be subject to redemption at the option of the Issuer, upon the written direction of the Company, in whole or in part, on the Business Day immediately succeeding any auction date at a redemption price of 100% of the principal amount thereof, together with accrued interest to the redemption date.

(vi) Whenever the Interest Rate Mode for the Bonds is the Long Term Rate, the Bonds will be subject to redemption at the option of the Issuer, upon the written direction of the Company, in whole or in part, (A) on the final Interest Payment Date for the then current Long Term Rate Period at a redemption price of 100% of the principal amount thereof and (B) prior to the end of the then current Long Term Rate Period at any time during the redemption periods and at the redemption prices set forth below, plus in each case interest accrued, if any, to the redemption date:

Original Length of Current Long Term Rate Period (Years)	Commencement of Redemption Period	Redemption Price as Percentage of Principal
2006 Series B Bonds:		
More than or equal to 11 years	First Interest Payment Date on or after the tenth anniversary of commencement of Long Term Rate Period	100%
Less than 11 years	Non-callable	Non-callable
2008 Series A Bonds:		
More than or equal to 10 years	First Interest Payment Date on or after the tenth anniversary of commencement of Long Term Rate Period	100%
Less than 10 years	Non-callable	Non-callable

Subject to certain conditions, including provision of an opinion of Bond Counsel that a change in the redemption provisions of the Bonds will not adversely affect the exclusion from gross income of interest on the Bonds for federal income tax purposes, the redemption periods and redemption prices may be revised, effective as of the Conversion Date, the date of a change in the Long Term Rate Period or a Purchase Date on the final Interest Payment Date during a Long Term Rate Period, to reflect Prevailing Market Conditions on such date as determined by the Remarketing Agent in its judgment. Any such revision of the redemption periods and redemption prices will not be considered an amendment or a supplement to the Indenture and will not require the consent of any Bondholder or any other person or entity.

Extraordinary Optional Redemption in Whole. The Bonds may be redeemed by the Issuer in whole at any time at 100% of the principal amount thereof plus accrued interest to the redemption date upon the exercise by the Company of an option under the Loan Agreement to prepay the loan if any of the following events occurs within 180 days preceding the giving of written notice by the Company to the Trustee of such election:

(i) if in the judgment of the Company, unreasonable burdens or excessive liabilities have been imposed upon the Company after the issuance of the Bonds with respect to the Project or the operation thereof, including without limitation federal, state or other ad valorem property, income or other taxes not imposed on the date of the Loan Agreement, other than ad valorem taxes levied upon privately owned property used for the same general purpose as the Project;

(ii) if the Project or a portion thereof or other property of the Company in connection with which the Project is used has been damaged or destroyed to such an extent so as, in the judgment of the Company, to render the Project or such other property of the Company in connection with which the Project is used unsatisfactory to the Company for its intended use, and such condition continues for a period of six months;

(iii) there has occurred condemnation of all or substantially all of the Project or the taking by eminent domain of such use or control of the Project or other property of the Company in connection with which the Project is used so as, in the judgment of the Company, to render the Project or such other property of the Company unsatisfactory to the Company for its intended use;

(iv) in the event changes, which the Company cannot reasonably control, in the economic availability of materials, supplies, labor, equipment or other properties or things necessary for the efficient operation of the generating station where the Project is located have occurred, which, in the judgment of the Company, render the continued operation of such generating station or any generating unit at such station uneconomical; or changes in circumstances after the issuance of the Bonds, including but not limited to changes in solid waste abatement, control and disposal requirements, have occurred such that the Company determines that use of the Project is no longer required or desirable;

(v) the Loan Agreement has become void or unenforceable or impossible of performance by reason of any changes in the Constitution of the Commonwealth of Kentucky or the Constitution of the United States of America or by reason of legislative or administrative action (whether state or federal) or any final decree, judgment or order of any court or administrative body, whether state or federal; or

(vi) a final order or decree of any court or administrative body after the issuance of the Bonds requires the Company to cease a substantial part of its operation at the generating station where the Project is located to such extent that the Company will be prevented from carrying on its normal operations at such generating station for a period of six months.

Extraordinary Optional Redemption in Whole or in Part. The Bonds are also subject to redemption in whole or in part at 100% of the principal amount thereof plus accrued interest to the redemption date at the option of the Company in an amount not to exceed the net proceeds received from insurance or any condemnation award received by the Issuer or the Company in the event of damage, destruction or condemnation of all or a portion of the Project, subject to receipt of an opinion of Bond Counsel that such redemption will not adversely affect the exclusion of interest on any of the Bonds from gross income for federal income tax purposes, and such net proceeds must be applied to reimburse the Credit Facility Issuer for drawings under the Credit Facility to redeem the Bonds. See "Summary of the Loan Agreement — Maintenance; Damage, Destruction and Condemnation." Such redemption may occur at any time, provided that if such event occurs while the Interest Rate Mode for the Bonds is the Flexible Rate or Semi-Annual Rate, such redemption must occur on a date on which the Bonds are otherwise subject to optional redemption as described above.

Mandatory Redemption; Determination of Taxability. The Bonds are required to be redeemed by the Issuer, in whole, or in such part as described below, at a redemption price equal to 100% of the principal amount thereof, without redemption premium, plus accrued interest, if any, to the redemption date, within 180 days following a "Determination of Taxability." As used herein, a "Determination of Taxability" means the receipt by the Trustee of written notice from a current or former registered owner of a Bond or from the Company or the Issuer of (i) the issuance of a published or private ruling or a technical advice memorandum by the Internal Revenue Service in which the Company participated or has been given the opportunity to participate, and which ruling or memorandum the Company, in its discretion, does not contest or from which no further right of administrative or judicial review or appeal exists, or (ii) a final determination from which no further right of appeal exists of any court of competent jurisdiction in the United States in a proceeding in which the Company has participated or has been a party, or has been given the opportunity to participate or be a party, in each case, to the effect that as a result of a failure by the Company to perform or observe any covenant or agreement or the inaccuracy of any representation contained in the Loan Agreement or any other agreement or certificate delivered in connection with the Bonds, the interest on the Bonds is included in the gross income of the owners thereof for federal income tax purposes, other than with respect to a person who is a "substantial user" or a "related person" of a substantial user of the Project within the meaning of the Section 147 of Internal Revenue Code of 1986, as amended (the "Code"); provided, however, that no such Determination of Taxability shall be considered to exist as a result of the Trustee receiving notice from a current or former registered owner of a Bond or from the Issuer unless (i) the Issuer or the registered owner or former registered owner of the Bond involved in such proceeding or action (A) gives the Company and the Trustee prompt notice of the commencement thereof, and (B) (if the Company agrees to pay all expenses in connection therewith) offers the Company the opportunity to control unconditionally the defense thereof, and (ii) either (A) the Company does not agree within 30 days of receipt of such offer to pay such expenses and liabilities and to control such defense, or (B) the Company shall exhaust or choose not to exhaust all available proceedings for the contest, review, appeal or rehearing of such decree, judgment or action which the Company determines to be appropriate. No Determination of Taxability described above will result from the inclusion of interest on any Bond in the computation of minimum or indirect taxes. All of the Bonds are required to be redeemed upon a Determination of Taxability as described above unless, in the opinion of Bond Counsel, redemption of a portion of such Bonds would have the result that interest payable on the remaining Bonds outstanding after the redemption would not be so included in any such gross income.

In the event any of the Issuer, the Company or the Trustee has been put on notice or becomes aware of the existence or pendency of any inquiry, audit or other proceedings relating to the Bonds being conducted by the Internal Revenue Service, the party so put on notice is required to give immediate written notice to the other parties of such matters. Promptly upon learning of the occurrence of a Determination of Taxability (whether or not the same is being contested), or any of the events described above, the Company is required to give notice thereof to the Trustee and the Issuer.

If the Internal Revenue Service or a court of competent jurisdiction determines that the interest paid or to be paid on any Bond (except to a "substantial user" of the Project or a "related person" within the meaning of Section 147(a) of the Code) is or was includable in the gross income of the recipient for federal income tax purposes for reasons other than as a result of a failure by the Company to perform or observe any of its covenants, agreements or representations in the Loan Agreement or any other agreement or certificate delivered in connection therewith, the Bonds are not subject to redemption. In such circumstances, Bondholders would continue to hold their Bonds, receiving principal and interest at the applicable rate as and when due, but would be required to include such interest payments in gross income for federal income tax purposes. Also, if the lien of the Indenture is discharged or defeased prior to the occurrence of a final Determination of Taxability, Bonds will not be redeemed as described herein.

General Redemption Terms. So long as a Credit Facility is in effect in respect of the Bonds, the redemption price (including accrued interest) will be paid from drawings under such Credit Facility or from moneys which otherwise constitute Available Moneys under the Indenture. Notice of redemption will be given by mailing a redemption notice conforming to the provisions and requirements of the Indenture by first class mail to the registered owners of the Bonds to be redeemed not less than 30 days (15 days if the Interest Rate Mode for the Bonds is the Flexible Rate, Daily Rate, Weekly Rate or, with respect to the 2006 Series B Bonds, the Dutch Auction Rate) but not more than 45 days prior to the redemption date.

Any notice mailed as provided in the Indenture will be conclusively presumed to have been given, irrespective of whether the owner receives the notice. Failure to give any such notice by mailing or any defect therein in respect of any Bond will not affect the validity of any proceedings for the redemption of any other Bond. No further interest will accrue on the principal of any Bond called for redemption after the redemption date if funds sufficient for such redemption have been deposited with the Paying Agent as of the redemption date. If the provisions for discharging the Indenture set forth below under the caption, "Summary of the Indenture — Discharge of Indenture" have not been complied with, any redemption notice will state that it is conditional on there being sufficient moneys to pay the full redemption price for the Bonds to be redeemed. So long as the Bonds are held in book-entry-only form, all redemption notices will be sent only to Cede & Co.

Book-Entry-Only System

Portions of the following information concerning DTC and DTC's book entry only system have been obtained from DTC. The Issuer, the Company and the Remarketing Agent make no representation as to the accuracy of such information.

Initially, DTC will act as securities depository for the Bonds and the Bonds initially will be issued solely in book-entry-only form to be held under DTC's book-entry-only system, registered in the name of Cede & Co. (DTC's partnership nominee). One fully registered bond in the aggregate principal amount of the Bonds will be deposited with DTC.

DTC, the world's largest depository, is a limited-purpose trust company organized under the New York Banking Law, a "banking organization" within the meaning of the New York Banking Law, a member of the Federal Reserve System, a "clearing corporation" within the meaning of the New York Uniform Commercial Code, and a "clearing agency" registered pursuant to the provisions of Section 17A of the Securities Exchange Act of 1934 (the "Exchange Act"). DTC holds and provides asset servicing for over 2.2 million issues of U.S. and non-U.S. equity, corporate and municipal debt issues, and money market instruments from over 100 countries that DTC's participants ("Direct Participants") deposit with DTC. DTC also facilitates the post-trade settlement among Direct Participants of sales and other securities transactions in deposited securities, through electronic computerized book-entry transfers and pledges between Direct Participants' accounts. This eliminates the need for physical movement of securities certificates. Direct Participants include both U.S. and non-U.S. securities brokers and dealers, banks, trust companies, clearing corporations, and certain other organizations. DTC is a wholly-owned subsidiary of The Depository Trust & Clearing Corporation ("DTCC"). DTCC, in turn, is owned by a number of Direct Participants of DTC and Members of the National Securities Clearing Corporation, Fixed Income Clearing Corporation, and Emerging Markets Clearing Corporation (NSCC, FICC and EMCC, also subsidiaries of DTCC), as well as by the New York Stock Exchange, Inc., the American Stock Exchange LLC and the National Association of Securities Dealers, Inc. Access to the DTC system is also available to others such as both U.S. and non-U.S. securities brokers and dealers, banks, trust companies, and clearing corporations that clear through or maintain a custodial relationship with a Direct Participant, either directly or indirectly ("Indirect Participants" and, together with "Direct Participants," "Participants"). DTC has Standard & Poor's highest rating: AAA. The DTC Rules applicable to its Participants are on file with the SEC. More information about DTC can be found at www.dtcc.com and www.dtc.org.

Purchases of the Bonds under the DTC system must be made by or through Direct Participants, which will receive a credit for the Bonds on DTC's records. The ownership interest of each actual purchaser of each Bond ("Beneficial Owner") is in turn to be recorded on the Direct and Indirect Participants' records. Beneficial Owners will not receive written confirmation from DTC of their purchase. Beneficial Owners are, however, expected to receive written confirmations providing details of the transaction, as well as periodic statements of their holdings, from the Direct or Indirect Participant through which the Beneficial Owner entered into the transaction. Transfers of ownership interests in the Bonds are to be accomplished by entries made on the books of Direct or Indirect Participants acting on behalf of Beneficial Owners.

Beneficial Owners will not receive certificates representing their ownership interests in the Bonds, except in the event that use of the book-entry system for the Bonds is discontinued.

To facilitate subsequent transfers, all Bonds deposited by Direct Participants with DTC are registered in the name of DTC's partnership nominee, Cede & Co. or such other name as may be requested by an authorized representative of DTC. The deposit of Bonds with DTC and their registration in the name of Cede & Co. or such other nominee do not effect any change in beneficial ownership. DTC has no knowledge of the actual Beneficial Owners of the Bonds; DTC's records reflect only the identity of the Direct Participants to whose accounts such Bonds are credited, which may or may not be the Beneficial Owners. The Direct and Indirect Participants will remain responsible for keeping account of their holdings on behalf of their customers.

Conveyance of notices and other communications by DTC to Direct Participants, by Direct Participants to Indirect Participants, and by Direct Participants and Indirect Participants to Beneficial Owners will be governed by arrangements among them, subject to any statutory or regulatory requirements as may be in effect from time to time.

Redemption notices shall be sent to DTC. If less than all of the Bonds are being redeemed, DTC's practice is to determine by lot the amount of the interest of each Direct Participant to be redeemed. .

Neither DTC nor Cede & Co. (nor such other DTC nominee) will consent or vote with respect to the Bonds unless authorized by a Direct Participant in accordance with DTC's Procedures. Under its usual procedures, DTC mails an Omnibus Proxy to the Issuer as soon as possible after the record date. The Omnibus Proxy assigns Cede & Co.'s consenting or voting rights to those Direct Participants to whose accounts the Bonds are credited on the record date (identified in a listing attached to the Omnibus Proxy).

Principal and interest payments on the Bonds will be made to Cede & Co. or such other nominee as may be requested by an authorized representative of DTC. DTC's practice is to credit Direct Participants' accounts, upon DTC's receipt of funds and corresponding detail information from the Issuer or the Trustee on the payable date in accordance with their respective holdings shown on DTC's records. Payments by Participants to Beneficial Owners will be governed by standing instructions and customary practices, as is the case with securities held for the accounts of customers in bearer form or registered in "street name," and will be the responsibility of such Participant and not of DTC nor its nominee, the Trustee, the Company or the Issuer, subject to any statutory or regulatory requirements as may be in effect from time to time. Payment of principal and interest to Cede & Co. (or such other nominee as may be requested by an authorized representative of DTC) is the responsibility of the Issuer or the Trustee, disbursement of such payments to Direct Participants will be the responsibility of DTC, and disbursement of such payments to the Beneficial Owners will be the responsibility of Direct and Indirect Participants.

A Beneficial Owner shall give notice to elect to have its Bonds purchased or tendered, through its Participant, to the Tender Agent, and shall effect delivery of such Bonds by causing the Direct Participant to transfer the Participant's interest in the Bonds, on DTC's records, to the Tender Agent. The requirement for physical delivery of Bonds in connection with a demand for purchase or a mandatory purchase will be deemed satisfied when the ownership rights in the Bonds are transferred by Direct Participants on DTC's records and followed by a book-entry credit of tendered Bonds to the Tender Agent's DTC account.

DTC may discontinue providing its services as securities depository with respect to the Bonds at any time by giving reasonable notice to the Issuer, the Company, the Tender Agent and the Trustee, or the Issuer, at the request of the Company, may remove DTC as the securities depository for the Bonds. Under such circumstances, in the event that a successor securities depository is not obtained, bond certificates are required to be delivered as described in the Indenture (see "— Revision of Book Entry Only System; Replacement Bonds" below). The Beneficial Owner, upon registration of certificates held in the Beneficial Owner's name, will become the registered owner of the Bonds.

So long as Cede & Co. is the registered owner of the Bonds, as nominee of DTC, references herein to the registered owners of the Bonds will mean Cede & Co. and will not mean the Beneficial Owners. Under the Indenture, payments made by the Trustee to DTC or its nominee will satisfy the Issuer's obligations under the Indenture, the Company's obligations under the Loan Agreement, to the extent of the payments so made. Beneficial Owners will not be, and will not be considered by the Issuer or the Trustee to be, and will not have any rights as, owners of Bonds under the Indenture.

The Trustee and the Issuer, so long as a book entry only system is used for the Bonds, will send any notice of redemption or of proposed document amendments requiring consent of registered owners and any other notices required by the document (including notices of Conversion and mandatory purchase) to be sent to registered owners only to DTC (or any successor securities depository) or its nominee. Any failure of DTC to advise any Direct Participant, or of any Direct Participant or Indirect Participant to notify the Beneficial Owner, of any such notice and its content or effect will not affect the validity of the redemption of the Bonds called for redemption, the document amendment, the Conversion, the mandatory purchase or any other action premised on that notice.

The Issuer, the Company, the Trustee and the Remarketing Agent cannot and do not give any assurances that DTC will distribute payments on the Bonds made to DTC or its nominee as the registered owner or any redemption or other notices, to the Participants, or that the Participants or others will distribute such payments or notices to the Beneficial Owners, or that they will do so on a timely basis, or that DTC will serve and act in the manner described in this Reoffering Circular.

THE ISSUER, THE COMPANY, THE REMARKETING AGENT AND THE TRUSTEE WILL HAVE NO RESPONSIBILITY OR OBLIGATION TO ANY DIRECT PARTICIPANT, INDIRECT PARTICIPANT OR ANY BENEFICIAL OWNER OR ANY OTHER PERSON NOT SHOWN ON THE REGISTRATION BOOKS OF THE TRUSTEE AS BEING A REGISTERED OWNER WITH RESPECT TO: (1) THE ACCURACY OF ANY RECORDS MAINTAINED BY DTC OR ANY DIRECT PARTICIPANT OR INDIRECT PARTICIPANT; (2) THE PAYMENT OF ANY AMOUNT DUE BY DTC TO ANY DIRECT PARTICIPANT OR BY ANY DIRECT PARTICIPANT OR INDIRECT PARTICIPANT TO ANY BENEFICIAL OWNER IN RESPECT OF THE PRINCIPAL AMOUNT OR REDEMPTION OR PURCHASE PRICE OF OR INTEREST ON THE BONDS; (3) THE DELIVERY OF ANY NOTICE BY DTC TO ANY DIRECT PARTICIPANT OR BY ANY DIRECT PARTICIPANT OR INDIRECT PARTICIPANT TO ANY BENEFICIAL OWNER WHICH IS REQUIRED OR PERMITTED TO BE GIVEN TO REGISTERED OWNERS UNDER THE TERMS OF THE INDENTURE; (4) THE SELECTION OF THE BENEFICIAL OWNERS TO RECEIVE PAYMENT IN THE EVENT OF ANY PARTIAL REDEMPTION OF THE BONDS; OR (5) ANY CONSENT GIVEN OR OTHER ACTION TAKEN BY DTC AS REGISTERED OWNER.

Revision of Book-Entry-Only System; Replacement Bonds. In the event that DTC determines not to continue as securities depository or is removed by the Issuer, at the direction of the Company, as securities depository, the Issuer, at the direction of the Company, may appoint a successor securities depository reasonably acceptable to the Trustee. If the Issuer does not or is unable to appoint a successor securities depository, the Issuer will issue and the Trustee will authenticate and deliver fully registered Bonds, in authorized denominations, to the assignees of DTC or their nominees.

In the event that the book-entry-only system is discontinued, the following provisions will apply. The Bonds may be issued in denominations of $5,000 and multiples thereof, if the Interest Rate Mode is the Semi-Annual Rate, the Annual Rate or the Long Term Rate; in denominations of $100,000 and multiples of $5,000 in excess thereof, if the Interest Rate Mode is the Flexible Rate; in denominations of $100,000 and multiples thereof, if the Interest Rate Mode is the Daily Rate or the Weekly Rate; and with respect to 2006 Series B Bonds, in denominations of $25,000 and multiples thereof; provided, that, (i) if the Bonds bear interest at the Daily Rate or the Weekly Rate, one Bond may be in the denomination of, or include an additional, $47,405 and (ii) if the Bonds bear interest at the Semi-Annual Rate, the Annual Rate, the Long Term Rate or the Flexible Rate, one Bond may be in the denomination of, or include an additional $2,405. Bonds may be transferred or exchanged for an equal total amount of Bonds of other authorized denominations upon surrender of such Bonds at the principal office of the Bond Registrar, accompanied by a written instrument of transfer or authorization for exchange in form and with guaranty of signature satisfactory to the Bond Registrar, duly executed by the registered owner or the owner's duly authorized attorney. Except as provided in the Indenture, the Bond Registrar will not be required to register the transfer or exchange of any Bond during the fifteen days before any mailing of a notice of redemption, after such Bond has been called for redemption in whole or in part, or after such Bond has been tendered or deemed tendered for optional or mandatory purchase as described under "Purchases of Bonds on Demand of Owner" and "Mandatory Purchases of Bonds." Registration of transfers and exchanges will be made without charge to the owners of Bonds, except that the Bond Registrar may require any owner requesting registration of transfer or exchange to pay any required tax or governmental charge.

Security; Limitation on Liens

Payment of the principal of and interest and any premium on the Bonds are secured by an assignment by the Issuer to the Trustee of the Issuer's interest in and to the Loan Agreement and all payments to be made pursuant thereto (other than certain indemnification and expense payments and notification rights). Pursuant to the Loan Agreement, the Company has agreed to pay, among other things, amounts sufficient to pay the aggregate principal amount of and premium, if any, on the Bonds, together with interest thereon as and when the same become due. The Company further will agree to make payments of the purchase price of the Bonds tendered for purchase to the extent that funds are not otherwise available therefor under the provisions of the Indenture.

The Bonds are unsecured general obligations of the Company, ranking on a parity with the Company's obligations under the Loan Agreement to make payments on the Bonds..

In the Loan Agreement, the Company has covenanted that it will not issue, assume or guarantee any debt for borrowed money secured by any mortgage, security interest, pledge, or lien ("mortgage") on any of the Company's operating property (as defined below), whether the Company owns it at the date hereof or acquires it later, and will not permit to exist any debt for borrowed money secured by a mortgage on any such property unless the Company similarly secures its obligations under the Loan Agreement to make payments to the Trustee in sufficient amounts to pay the principal of, premium, if any, and interest required to be paid on the Bonds. This restriction will not apply to:

- mortgages on any property existing at the time the Company acquires the property or at the time the Company acquires the corporation owning the property;
- purchase money mortgages;
- specified governmental mortgages; or
- any extension, renewal or replacement (or successive extensions, renewals or replacements) of any mortgage referred to in the three clauses listed above, so long as the principal amount of indebtedness secured under this clause and not otherwise authorized by the clauses listed above does not exceed the principal amount of indebtedness secured at the time of the extension, renewal or replacement.

In addition, the Company can also issue secured debt so long as the amount of the secured debt does not exceed the greater of 10% of net tangible assets or 10% of capitalization.

The Company will not, so long as any of the Bonds are outstanding, issue, assume, guarantee or permit to exist any debt of the Company secured by a mortgage, the creditor of which controls, is controlled by or is under common control with, the Company.

For purposes of this limitation on liens, "operating property" means (i) any interest in real property owned by the Company and (ii) any asset owned by the Company that is depreciable in accordance with generally accepted accounting principles.

The Letter of Credit

The following summarizes certain provisions of the Letter of Credit and the Reimbursement Agreement, to which reference is made for the detailed provisions thereof. Unless otherwise defined in this Reoffering Circular, capitalized terms in the following summary are used as defined in the Letter of Credit and the Reimbursement Agreement. The Company is permitted under the Indenture to deliver an Alternate Credit Facility to replace the related Letter of Credit. Any such Alternate Credit Facility must meet certain requirements described in the Indenture.

The Letter of Credit

The Letter of Credit will be an irrevocable transferable direct pay letter of credit issued by the Bank in order to provide additional security for the payment of principal of, purchase price of, interest on and premium, if applicable, on any date when payments under the Bonds are due, including principal and interest payments and payments upon tender, redemption, acceleration or maturity of the Bonds. The Letter of Credit will provide for direct payments to or upon the order of the Trustee as set forth in the Letter of Credit in amounts sufficient to pay to or upon the order of the Trustee, upon request and in accordance with the terms thereof.

The Letter of Credit will be issued in an amount equal to the aggregate principal amount of the outstanding Bonds, plus an amount that represents interest accrued thereon at an assumed rate of 15% per annum for 45 days (the "Credit Amount"). The Trustee, upon compliance with the terms of the Letter of Credit, is authorized to draw up to (a) an amount sufficient (i) to pay principal of the Bonds, when due, whether at maturity or upon redemption or acceleration, and (ii) to pay the portion of the purchase price of the Bonds delivered for purchase pursuant to a demand for purchase by the owner thereof or a mandatory tender for purchase and not remarketed (a "Liquidity Drawing") equal to the principal amount of the Bonds, plus (b) an amount not to exceed 45 days of accrued interest on such Bonds at an assumed rate of 15% per annum (i) to pay interest on the Bonds, when due, and (ii) to pay the portion of the purchase price of the Bonds, delivered for purchase pursuant to a demand for purchase by the owner thereof or a mandatory tender for purchase and not remarketed, equal to the interest accrued, if any, on the Bonds.

The amount available under the Letter of Credit will be automatically reduced by the amount of any drawing thereunder, subject to reinstatement as described below. With respect to a drawing by the Trustee solely to pay interest on the Bonds on an Interest Payment Date, the amount available under the Letter of Credit will be automatically reinstated in the amount of such drawing effective on the earlier of (i) receipt by the Bank from the Company of reimbursement of any drawing solely to pay interest in full or (ii) at the opening of business on the eleventh calendar day after the date the Bank honors such drawing, unless the Trustee has received written notice from the Bank by the tenth calendar day after the date the Bank honors such drawing the Bank is not so reinstating the available amount due to the Company's failure to reimburse the Bank for such drawing in full, or that an event of default has occurred and is continuing under the Reimbursement Agreement and, in either case, directing, an acceleration of the Bonds pursuant to the Indenture. With respect to a Liquidity Drawing under the Letter of Credit, the amount available under the Letter of Credit will be automatically reduced by the principal amount of the Bonds purchased with the proceeds of such drawing plus the amount of accrued interest on such Bonds. In the event of the remarketing of the Bonds purchased with the proceeds of a Liquidity Drawing, the amount available under the Letter of Credit will be automatically reinstated upon receipt by the Bank or the Trustee on the Bank's behalf of an amount equal to such principal amount plus accrued interest.

The Letter of Credit will terminate on the earliest to occur of:

(a) the Bank's close of business on December 18, 2009 (such date, as extended from time to time in accordance with the Letter of Credit is defined as the "Stated Expiration Date");

(b) the Bank's close of business on the date which is five Business Days following the date of receipt by the Bank of a certificate from the Trustee certifying that (a) no Bonds remain Outstanding within the meaning of the Indenture, (b) all drawings required to be made under the Indenture and available under the Letter of Credit have been made and honored, (c) an Alternate Credit Facility has been delivered to the Trustee in accordance with the Indenture to replace the Letter of Credit or (d) all of the outstanding Bonds were converted to Bonds bearing interest at a rate other than the Daily Rate or the Weekly Rate;

(c) the Bank's close of business on the date of receipt by the Bank of a certificate from the Trustee confirming that the Trustee is required to terminate the Letter of Credit in accordance with the terms of the Indenture; or

(d) the date on which the Bank receives and honors an acceleration drawing certificate.

The Reimbursement Agreement

Pursuant to the Reimbursement Agreement, the Company is obligated to reimburse the Bank for all amounts drawn under the Letter of Credit, and to pay interest on all such amounts. The Company has also agreed to pay the Bank a periodic fee for issuing and maintaining the Letter of Credit.

The Reimbursement Agreement imposes various covenants and agreements, including various financial and operating covenants, on the Company. Such covenants include, but are not limited to, covenants relating to (i) inspection of the books and financial records of the Company; (ii) creation of liens; (iii) liquidations, mergers, consolidations or sales of all or substantially all of the Company's assets; and (iv) disposition of assets. Any such covenants may be amended, waived or modified at any time by the Bank and without the consent of the Trustee or the holders of the Bonds. Under certain circumstances, the failure of the Company to comply with such covenants may result in a mandatory tender or acceleration of the Bonds.

The following events will constitute an "event of default" under the Reimbursement Agreement:

(a) nonpayment of certain fees and other amounts required to be paid or reimbursed by the Company under the Reimbursement Agreement to the Bank within five days after the same was required to be paid;

(b) any representation or warranty made or deemed made by or on behalf of the Company or any of its Significant Subsidiaries to the Bank under or in connection with the Reimbursement Agreement or any other Transaction Document, any advance or any certificate or information delivered pursuant to or in connection with the Reimbursement Agreement or any other Transaction Document, was false or misleading in any material respect as of the time it was made or furnished;

(c) an "event of default" (not due to the Bank's failure to properly honor a drawing on the Letter of Credit) occurred under the Indenture or any of the other Transaction Documents and any applicable grace period has expired;

(d) the breach by the Company or any of its Significant Subsidiaries of any of the terms or provisions of certain covenants contained in the Reimbursement Agreement including, but not limited to, covenants relating to the provision of notice to the Bank regarding an "event of default" or "default" under the Reimbursement Agreement, the corporate existence and license or qualification and good standing of the Company in jurisdictions in which it owns or leases property, the creation of liens, the liquidation, merger, consolidation or sale of all or substantially all of the assets of the Company and the disposition of assets;

(e) the breach by the Company or any of its Significant Subsidiaries (other than a breach which constitutes a "default" described above) of any of the terms or provisions of the Reimbursement Agreement or any Security Document that is not remedied within thirty (30) days after an executive officer of the Company has actual knowledge of such default or written notice of such default has been given to the Company by the Bank;

(f) the Bonds cease to be valid for any reason;

(g) a default or event of default has occurred at any time under the terms of any other agreement involving borrowed money or the extension of credit or any other Indebtedness under which the Company or any of its Significant Subsidiaries may be obligated for the payment of $50,000,000 or more in the aggregate, and such breach, default or event of default continues beyond any period of grace permitted with respect thereto and as a result thereof such Indebtedness is accelerated, becomes due or is otherwise required to be repurchased or redeemed prior to the scheduled date of maturity thereof;

(h) a proceeding has been instituted in a court having jurisdiction in the premises seeking a decree or order for relief in respect of the Company or any Significant Subsidiary in an involuntary case under any applicable bankruptcy, insolvency, reorganization or other similar law now or hereafter in effect, or for the appointment of a receiver, liquidator, assignee, custodian, trustee, sequestrator, conservator (or similar official) of the Company or any Significant Subsidiary for any substantial part of its property, or for the winding-up or liquidation of its affairs, and such proceeding shall remain undismissed or unstayed and in effect for a period of sixty (60) consecutive days; such court shall enter a decree or order granting any of the relief sought in such proceeding; or the Company or any Significant Subsidiary shall consent, approve or otherwise acquiesce in any of the actions sought in such proceeding;

(i) the Company or any Significant Subsidiary shall commence a voluntary case under any applicable bankruptcy, insolvency, reorganization or other similar law now or hereafter in effect, shall consent to the entry of an order for relief in an involuntary case under any such law, or shall consent to the appointment or taking possession by a receiver, liquidator, assignee, custodian, trustee, sequestrator, conservator (or other similar official) of itself or for any substantial part of its property or shall make a general assignment for the benefit of creditors, or shall fail generally to pay its debts as they become due, or shall take any action in furtherance of any of the foregoing;

(j) without the application, approval or consent of the Company or any of its Significant Subsidiaries, a receiver, trustee, examiner, liquidator or similar official shall be appointed for the Company or any of its Significant Subsidiaries, or for any substantial portion of its Property, or a proceeding described in paragraph (h) above has been instituted against the Company or any of its Significant Subsidiaries, and such appointment continues undischarged or such proceeding continues undismissed or unstayed for a period of 60 consecutive days;

(k) any of the following occurs: (i) any Reportable Event which constitutes grounds under Section 4042 of ERISA for the termination of any Plan by the PBGC or the appointment of a trustee to administer or liquidate any Plan, shall have occurred and be continuing; (ii) a notice of intent to terminate any Plan shall have been filed with the PBGC under Section 4041 of ERISA; (iii) the PBGC shall give notice under Section 4042 of ERISA of its intent to institute proceedings to terminate any Plan or Plans or to appoint a trustee to administer or liquidate any Plan; (iv) the Company or any member of the ERISA Group shall fail to make any contributions when due to a Plan or a Multiemployer Plan; (v) the Company or any member of the ERISA Group shall make any amendment to a Plan with respect to which security is required under Section 307 of ERISA; (vi) the Company or any member of the ERISA Group shall withdraw completely or partially from a Multiemployer Plan pursuant to Subtitle E of Title IV of ERISA; or (vii) the Company or any member of the ERISA Group shall withdraw within the meaning of Section 4063 of ERISA (or shall be deemed under Section 4062(e) of ERISA to withdraw) from a Multiple Employer Plan; and, with respect to any of such events specified in clause (i), (ii), (iii), (iv), (v), (vi) or (vii), such occurrence would be reasonably likely to result in a Material Adverse Effect;

(l) any final judgment(s) or order(s) for the payment of money shall be entered against the Company or any of its Significant Subsidiaries by a court having jurisdiction in the premises which judgment is not discharged, vacated, bonded or stayed pending appeal within a period of thirty (30) days from the date of entry if the aggregate uninsured amount of all such judgments and orders exceeds $50,000,000;

(m) the Company or any of its Significant Subsidiaries ceases to conduct business (other than as permitted hereunder) or the Company is enjoined, restrained or in any way prevented by court order from conducting all or any material part of its business and such injunction, restraint or other preventive order is not dismissed within thirty (30) days after the entry thereof; or

(n) E.ON AG fails to own, directly or indirectly, at least seventy-five percent (75%) of the outstanding Voting Capital of the Company.

For purposes of the foregoing:

"Bond Documents" means the Indenture, the Custody Agreement, the Loan Agreement, the Bonds and the Remarketing Agreement.

"Material Adverse Effect" means (i) a material adverse change in the business, property, condition (financial or otherwise), operations or results of operations of the Company and its subsidiaries taken as a whole, (ii) a material adverse change in the ability of the Company to perform its obligation under the Transaction Documents or (iii) a material adverse change in the validity or enforceability of any of the Transaction Documents or the rights or remedies of the Bank thereunder.

"Security Documents" means the Custody, Pledge and Security Agreement dated as of December 19, 2008 among the Trustee, the Company and the Bank with respect to any Bond purchased during the period from and including the date of its purchase with proceeds of a Liquidity Drawing to but excluding the date on which such Bond is purchased by any person as a result of a remarketing of such Bond pursuant to the Remarketing Agreement and the Indenture.

"Transaction Documents" means, collectively, the Reimbursement Agreement, Bond Documents, the Security Documents and all other operative documents relating to the issuance, sale and securing of the Bonds (including without limitation any document(s) or instrument(s) through which the Bonds are now or hereafter collateralized, such as mortgages, security agreements, etc.).

Summary of the Loan Agreement

The following, in addition to the provisions contained elsewhere in this Reoffering Circular, is a brief description of certain provisions of the Loan Agreement. This description is only a summary and does not purport to be complete and definitive. Reference is made to the Loan Agreement for the detailed provisions thereof.

General

The Loan Agreement initially commenced as of its initial date, and, with respect to the 2006 Series A Bonds, is amended and restated as of September 1, 2008, and will end on the earliest to occur of October 1, 2034, with respect to the 2006 Series B Bonds, or February 1, 2032, with respect to the 2008 Series A Bonds, or the date on which all of the Bonds have been fully paid or provision has been made for such payment pursuant to the Indenture. See "Summary of the Indenture — Discharge of Indenture."

The Company has agreed to repay the loan pursuant to the Loan Agreement by making timely payments to the Trustee in sufficient amounts to pay the principal of, premium, if any, and interest required to be paid on the Bonds on each date upon which any such payments are due. The Company has also agreed to pay (a) the agreed upon fees and expenses of the Trustee, the Bond Registrar, the Tender Agent and the Paying Agent and all other amounts which may be payable to the Trustee, the Bond Registrar, the Paying Agent, the Auction Agent with respect to the 2006 Series B Bonds, and the Tender Agent, as may be applicable, under the Indenture, (b) the expenses in connection with any redemption of the Bonds and (c) the reasonable expenses of the Issuer.

The Company covenants and agrees with the Issuer that it will cause the purchase of tendered Bonds that are not remarketed in accordance with the Indenture and, to that end, the Company will cause funds to be made available to the Tender Agent at the times and in the manner required to effect such purchases in accordance with the Indenture; provided, however, that the obligation of the Company to make any such payment will be reduced by the amount of (A) moneys paid by the Remarketing Agent as proceeds of the remarketing of such Bonds; (B) moneys drawn under a Credit Facility, if any, for the purpose of paying such purchase price and (C) other moneys made available by the Company (see "Summary of the Bonds — Remarketing and Purchase of Bonds").

All payments to be made by the Company to the Issuer pursuant to the Loan Agreement (except the fees and reasonable out-of-pocket expenses of the Issuer, the Trustee, the Paying Agent, the Bond Registrar, the Auction Agent with respect to the 2006 Series B Bonds and the Tender Agent, and amounts related to indemnification) have been assigned by the Issuer to the Trustee, and the Company will pay such amounts directly to the Trustee. The obligations of the Company to make the payments pursuant to the Loan Agreement are absolute and unconditional.

Maintenance of Tax Exemption

The Company and the Issuer have agreed not to take any action that would result in the interest paid on the Bonds being included in gross income of any Bondholder (other than a holder who is a "substantial user" of the Project or a "related person" within the meaning of Section 147(a) of the Code) for federal income tax purposes or that adversely affects the validity of the Bonds.

Limitation on Liens

The Company has agreed that, so long as any of the Bonds are outstanding, it will not create, assume or guarantee debt for borrowed money secured by any mortgage, except as described above under "Security; Limitation on Liens."

Payment of Taxes

The Company has agreed to pay certain taxes and other governmental charges that may be lawfully assessed, levied or charged against or with respect to the Project (see, however, subparagraph (i) under "Summary of the Bonds — Redemptions — Extraordinary Optional Redemption in Whole"). The Company may contest such taxes or other governmental charges unless the security provided by the Indenture would be materially endangered.

Maintenance; Damage, Destruction and Condemnation

So long as any Bonds are outstanding, the Company will maintain the Project or cause the Project to be maintained in good working condition and will make or cause to be made all proper repairs, replacements and renewals necessary to continue to constitute the Project as solid waste disposal facilities under Section 142(a)(6) of the Code and the Act. However, the Company will have no obligation to maintain, repair, replace or renew any portion of the Project, the maintenance, repair, replacement or renewal of which becomes uneconomical to the Company because of certain events, including damage or destruction by a cause not within the Company's control, condemnation of the Project, change in government standards and regulations, economic or other obsolescence or termination of operation of generating facilities to the Project.

The Company, at its own expense, may remodel the Project or make substitutions, modifications and improvements to the Project as it deems desirable, which remodeling, substitutions, modifications and improvements will be deemed, under the terms of the Loan Agreement to be a part of the Project. The Company may not, however, change or alter the basic nature of the Project or cause it to lose its status under Section 142(a)(6) of the Code and the Act.

If, prior to the payment of all Bonds outstanding, the Project or any portion thereof is destroyed, damaged or taken by the exercise of the power of eminent domain and the Issuer or the Company receives net proceeds from insurance or a condemnation award in connection therewith, the Company must (i) cause such net proceeds to be used to repair or restore the Project or (ii) reimburse the Credit Facility Issuer for drawings under the Credit Facility for the redemption of the Bonds in whole or in part at their principal amount, which, by the opinion of Bond Counsel, will not adversely affect the exclusion of the interest on the Bonds from gross income for federal income tax purposes. See "Summary of the Bonds — Redemptions — Extraordinary Optional Redemption in Whole or in Part."

Project Insurance

The Company will insure the Project in a manner consistent with general industry practice.

Assignment, Merger and Release of Obligations of the Company

The Company may assign the Loan Agreement, pursuant to an opinion of Bond Counsel that such assignment will not adversely affect the exclusion of the interest on the Bonds from gross income for federal income tax purposes, without obtaining the consent of either the Issuer or the Trustee. Such assignment, however, will not relieve the Company from primary liability for any of its obligations under the Loan Agreement and performance and observance of the other covenants and agreements to be performed by the Company. The Company may dispose of all or substantially all of its assets or consolidate with or merge into another corporation, provided the acquirer of the Company's assets or the corporation with which it will consolidate with or merge into is a corporation or other business organization organized and existing under the laws of the United States of America or one of the states of the United States of America or the District of Columbia, is qualified and admitted to do business in the Commonwealth of Kentucky, assumes in writing all of the obligations and covenants of the Company under the Loan Agreement and delivers a copy of such assumption to the Issuer and Trustee.

Release and Indemnification Covenant

The Company will indemnify and hold the Issuer harmless against any expense or liability incurred, including attorneys' fees, resulting from any loss or damage to property or any injury to or death of any person occurring on or about or resulting from any defect in the Project or from any action commenced in connection with the financing thereof.

Events of Default

Each of the following events constitutes an "Event of Default" under the Loan Agreement:

(1) failure by the Company to pay the amounts required for payment of the principal of, including purchase price for tendered Bonds and redemption and acceleration prices, and interest accrued, on the Bonds, at the times specified therein taking into account any periods of grace provided in the Indenture and the Bonds for the applicable payment of interest on the Bonds (see "Summary of the Indenture — Defaults and Remedies");

(2) failure by the Company to observe and perform any covenant, condition or agreement, other than as referred to in paragraph (1) above, for a period of thirty days after written notice by the Issuer or Trustee, provided, however, that if such failure is capable of being corrected, but cannot be corrected in such 30-day period, it will not

constitute an Event of Default under the Loan Agreement if corrective action with respect thereto is instituted within such period and is being diligently pursued;

(3) certain events of bankruptcy, dissolution, liquidation, reorganization or insolvency of the Company; or

(4) the occurrence of an Event of Default under the Indenture.

Under the Loan Agreement, certain of the Company's obligations (other than the Company's obligations, among others, (i) not to permit any action which would result in interest paid on the Bonds being included in gross income for federal and Kentucky income taxes; (ii) to maintain its corporate existence and good standing, and to neither dispose of all or substantially all of its assets or consolidate with or merge into another corporation unless certain provisions of the Loan Agreement are satisfied; and (iii) to make loan payments and certain other payments under the provisions of the Loan Agreement) may be suspended if by reason of force majeure (as defined in the Loan Agreement) the Company is unable to carry out such obligations.

Remedies

Upon the happening of an Event of Default under the Loan Agreement, the Trustee, on behalf of the Issuer, may, among other things, take whatever action at law or in equity may appear necessary or desirable to collect the amounts then due and thereafter to become due, or to enforce performance and observance of any obligation, agreement or covenant of the Company, under the Loan Agreement.

Any amounts collected upon the happening of any such Event of Default must be applied in accordance with the Indenture or, if the Bonds have been fully paid (or provision for payment thereof has been made in accordance with the Indenture) and all other liabilities of the Company accrued under the Indenture and the Loan Agreement have been paid or satisfied, made available to the Company.

Options to Prepay, Obligation to Prepay

The Company may prepay the loan pursuant to the Loan Agreement, in whole or in part, on certain dates, at the prepayment prices as shown under the captions "Summary of the Bonds — Redemptions — Optional Redemption," "— Extraordinary Optional Redemption in Whole" and "— Extraordinary Optional Redemption in Whole or in Part." Upon the occurrence of the event described under the caption "Summary of the Bonds — Redemptions — Mandatory Redemption; Determination of Taxability," the Company will be obligated to prepay the loan in an aggregate amount sufficient to redeem the required principal amount of the Bonds.

In each instance, the loan prepayment price must be a sum sufficient, together with other funds deposited with the Trustee and available for such purpose, to redeem the requisite amount of the Bonds at a price equal to the applicable redemption price plus accrued interest to the redemption date, and to pay all reasonable and necessary fees and expenses of the Trustee, the Paying Agent and, with respect to the 2008 Series A Bonds, the Bond Registrar and the Tender Agent and all other liabilities of the Company under the Loan Agreement accrued to the redemption date.

Amendments and Modifications

No amendment or modification of the Loan Agreement is permissible without the written consent of the Trustee. The Issuer and the Trustee may, however, without the consent of or notice to any Bondholders, enter into any amendment or modification of the Loan Agreement (i) which may be required by the provisions of the Loan Agreement or the Indenture, (ii) for the purpose of curing any ambiguity or formal defect or omission, (iii) in connection with any modification or change necessary to conform the Loan Agreement with changes and modifications in the Indenture or (iv) in connection with any other change which, in the judgment of the Trustee, does not adversely affect the Trustee or the Bondholders. Except for such amendments, the Loan Agreement may be amended or modified only with the consent of the Bondholders holding a majority in principal amount of the Bonds then outstanding (see "Summary of the Indenture — Supplemental Indentures" for an explanation of the procedures necessary for Bondholder consent); provided, however, that the approval of the Bondholders holding 100% in principal amount of the Bonds then outstanding is necessary to effectuate an amendment or modification with respect to the Loan Agreement of the type described in clauses (i) through (iv) of the first sentence of the second paragraph of "Summary of the Indenture — Supplemental Indentures." Any amendments, changes or modification of the Loan Agreement that require the consent of the Bondholders must additionally be approved by the Credit Facility Issuer, if the Bonds are at the time secured by a Credit Facility. Additionally, so long as a Credit Facility is in place or while any amounts are outstanding under a Reimbursement Agreement, the Credit Facility Issuer must consent in writing to any amendment, change, or modification to the Agreement.

Summary of the Indenture

The following, in addition to the provisions contained elsewhere in this Reoffering Circular, is a brief description of certain provisions of the Indenture. This description is only a summary and does not purport to be complete and definitive. Reference is made to the Indenture for the detailed provisions thereof.

Security

Pursuant to the Indenture, the Issuer has assigned and pledged to the Trustee its interest in and to the Loan Agreement, including payments and other amounts due the Issuer thereunder, together with all moneys, property and securities from time to time held by the Trustee under the Indenture (with certain exceptions, including moneys held in or earnings on the Rebate Fund and the Purchase Fund). The Bonds are not directly secured by the Project.

No Pecuniary Liability of the Issuer

No provision, covenant or agreement contained in the Indenture or in the Loan Agreement, nor any breach thereof, will constitute or give rise to any pecuniary liability of the Issuer or any charge upon any of its assets or its general credit or taxing powers. The Issuer has not obligated itself by making the covenants, agreements or provisions contained in the Indenture or in the Loan Agreement, except with respect to the Project and the application of the amounts assigned to payment of the principal of, premium, if any, and interest on the Bonds.

The Bond Fund

The payments to be made by the Company pursuant to the Loan Agreement to the Issuer and certain other amounts specified in the Indenture will be deposited into a Bond Fund established pursuant to the Indenture (the "Bond Fund") and will be maintained in trust by the Trustee. Moneys in the Bond Fund will be used for the payment of the principal of, premium, if any, and interest on the Bonds, and for the redemption of Bonds prior to maturity in the following order of priority: (i) proceeds of the Credit Facility, if any, deposited into the Bond Fund in accordance with the Indenture and (ii) any other moneys provided by or on behalf of the Company. Any moneys held in the Bond Fund will be invested by the Trustee at the specific written direction of the Company in certain Governmental Obligations, investment-grade corporate obligations and other investments permitted under the Indenture.

So long as a Credit Facility is in held by the Trustee and there is no default in the payment of principal or redemption price of or interest on the Bonds, any amounts in the Bond Fund provided by or on behalf of the Company will be paid to the Credit Facility Issuer to the extent of any amounts that the Company owes the Credit Facility Issuer pursuant to the Reimbursement Agreement. Any amounts remaining in the Bond Fund (first, from the proceeds of the Credit Facility, and second, from the moneys provided by or on behalf of the Company) after payment in full of the principal or redemption price of and interest on the Bonds (or provision for payment thereof) and payment of any outstanding fees and expenses of the Trustee (including its reasonable attorney fees and expenses) will be paid, first, to the Credit Facility Issuer, to the extent of any amounts that the Company owes the Credit Facility Issuer pursuant to the Reimbursement Agreement and, second, to the Company. Any amounts remaining in the Bond Fund (i) after all of the outstanding Bonds have been paid and discharged, (ii) after payment of all fees, charges and expenses to the Issuer, the Trustee, the Registrar and the Paying Agent and of all other amounts required to be paid under the Indenture and the Loan Agreement and (iii) after the receipt by the Trustee of the written request of the Company for such payment, will be paid to the Credit Facility Issuer, if any, to the extent of any amounts that the Company owes to such Credit Facility Issuer pursuant to the Reimbursement Agreement, and then to the Company to the extent that those moneys are in excess of the amounts necessary to effect the payment and discharge of the outstanding Bonds.

The Rebate Fund

A Rebate Fund has been created by the Indenture (the "Rebate Fund") and will be maintained as a separate fund free and clear of the lien of the Indenture. The Issuer, the Trustee and the Company have agreed to comply with all rebate requirements of the Code and, in particular, the Company has agreed that if necessary, it will deposit in the Rebate Fund any such amount as is required under the Code. However, the Issuer, the Trustee and the Company may disregard the Rebate Fund provisions to the extent that they receive an opinion of Bond Counsel that such failure to comply will not adversely affect the exclusion of the interest on the Bonds from gross income for federal income tax purposes.

Discharge of Indenture

When all the Bonds and all fees and charges accrued and to accrue of the Trustee and the Paying Agent have been paid or provided for, and when proper notice has been given to the Bondholders or the Trustee that the proper amounts have been so paid or provided for, and if the Issuer is not in default in any other respect under the Indenture, the Indenture will become null and void. The Bonds will be deemed to have been paid and discharged when there have been irrevocably deposited with the Trustee moneys sufficient to pay the principal, premium, if any, and accrued interest on such Bonds to the due date (whether such date be by reason of maturity or upon redemption) or, in lieu thereof, Governmental Obligations have been deposited which mature in such amounts and at such times as will provide the funds necessary to so pay such Bonds, and when all reasonable and necessary fees and expenses of the Trustee, the Tender Agent, the Authenticating Agent, the Bond Registrar and the Paying Agent have been paid or provided for.

Notwithstanding anything to the contrary, if any Bonds are rated by a rating service, no such Bonds will be deemed to have been paid and discharged by reason of any deposit pursuant to the Indenture, unless each such rating service has confirmed in writing to the Trustee that its rating will not be withdrawn or lowered as a result of any such deposit.

So long as the Company owes any amounts to the Credit Facility Issuer, if any, pursuant to the Reimbursement Agreement: (A) the lien of the Indenture may not be discharged; (B) such Credit Facility Issuer shall be subrogated to the extent of such amounts owed by the Company to such Credit Facility Issuer to all rights of the Bondholders to enforce the payment of the Bonds from the revenues and all other rights of the Bondholders under the Bonds, the Indenture and the Loan Agreement; (C) the Bondholders will be deemed paid to the extent of money drawn by the Trustee under the Credit Facility; and (D) subject to the Indenture, the Trustee will sign, execute and deliver all documents or instruments and do all things that may be reasonably required by the Credit Facility Issuer to effect the Credit Facility Issuer's subrogation of rights of enforcement and remedies set forth in the Indenture.

Defaults and Remedies

Each of the following events constitutes an "Event of Default" under the Indenture:

(a) Failure to make payment of any installment of interest on any Bond, (i) if such Bond bears interest at other than the Long Term Rate, within a period of one Business Day from the due date and (ii) if such Bond bears interest at the Long Term Rate, within a period of five Business Days from the date due;

(b) Failure to make punctual payment of the principal of, or premium, if any, on any Bond on the due date, whether at the stated maturity thereof, or upon proceedings for redemption, or upon the maturity thereof by declaration or if payment of the purchase price of any Bond required to be purchased pursuant to the Indenture is not made when such payment has become due and payable;

(c) Failure of the Issuer to perform or observe any other of the covenants, agreements or conditions in the Indenture or in the Bonds which failure continues for a period of 30 days after written notice by the Trustee, provided, however, that if such failure is capable of being cured, but cannot be cured in such 30-day period, it will not constitute an Event of Default under the Indenture if corrective action in respect of such failure is instituted within such 30-day period and is being diligently pursued;

(d) The occurrence of an "Event of Default" under the Loan Agreement (see "Summary of the Loan Agreement — Events of Default");

(e) written notice from the Credit Facility Issuer to the Trustee of an event of default under the Reimbursement Agreement, by reason of which the Trustee has been directed to accelerate the Bonds; or

(f) if a Credit Facility is then held by the Trustee, on or before the close of business on the tenth calendar day following the honoring of a drawing under such Credit Facility to pay interest on the Bonds on an Interest Payment Date, written notice from the Credit Facility Issuer to the Trustee that the interest component of the Credit Facility will not be reinstated.

Upon the occurrence of an Event of Default under clauses (a), (b), (e) or (f) above, the Trustee must: (i) declare the principal of all Bonds and interest accrued thereon to be immediately due and payable; (ii) declare all payments under the Loan Agreement to be immediately due and payable and enforce each and every other right granted to the Issuer under the Loan Agreement for the benefit of the Bondholders; and (iii) if a Credit Facility securing the Bonds is in effect, make an immediate drawing under the Credit Facility in accordance with its terms and deposit the proceeds of such drawing in the Bond Fund pending application to the payment of principal of the Bonds, subject to the provisions of the Indenture reserving to the Credit Facility Issuer the right to direct default proceedings and providing for termination of default proceedings upon certain occurrences.

Interest on the Bonds will cease to accrue on the date of issuance of the declaration of acceleration of payment of principal and interest on the Bonds.

In exercising such rights, the Trustee will take any action that, in the judgment of the Trustee, would best serve the interests of the registered owners. Upon the occurrence of an Event of Default under the Indenture, the Trustee may also proceed to pursue any available remedy by suit at law or in equity to enforce the payment of the principal of, premium, if any, and interest on the Bonds then outstanding.

If the Trustee recovers any moneys following an Event of Default, unless the principal of the Bonds has been declared due and payable, all such moneys will be applied in the following order: (i) to the payment of the fees, expenses, liabilities and advances incurred or made by the Trustee and the Paying Agent and the payment of any sums due and payable to the United States pursuant to Section 148(f) of the Code, (ii) to the payment of all interest then due on the Bonds and (iii) to the payment of unpaid principal and premium, if any, of the Bonds. If the principal of the Bonds has become due or has been accelerated, such moneys will be applied in the following order: (i) to the payment of the fees, expenses, liabilities and advances incurred or made by the Trustee and the Paying Agent and (ii) to the payment of principal of and interest then due and unpaid on the Bonds. In each case, however, Trustee and Paying Agent fees or costs will not be payable from moneys derived from Credit Facility drawings, any remarketing proceeds or moneys constituting certain Available Moneys under the Indenture.

No Bondholder may institute any suit or proceeding in equity or at law for the enforcement of the Indenture unless an Event of Default has occurred of which the Trustee has been notified or is deemed to have notice, and registered owners holding not less than 25% in aggregate principal amount of Bonds then outstanding have made written request to the Trustee to proceed to exercise the powers granted under the Indenture or to institute such action in their own name and the Trustee fails or refuses to exercise its powers within a reasonable time after receipt of indemnity satisfactory to it.

Any judgment against the Issuer pursuant to the exercise of rights under the Indenture will be enforceable only against specific assigned payments, funds and accounts under the Indenture in the hands of the Trustee. No deficiency judgment will be authorized against the general credit of the Issuer.

No default under paragraph (c) above will constitute an Event of Default until actual notice is given to the Issuer and the Company by the Trustee or to the Issuer, the Company and the Trustee by the registered owners holding not less than 25% in aggregate principal amount of all Bonds outstanding and the Issuer and the Company have had thirty days after such notice to correct the default and failed to do so. If the default is such that it cannot be corrected within the applicable period but is capable of being cured, it will not constitute an Event of Default if corrective action is instituted by the Issuer or the Company within the applicable period and diligently pursued until the default is corrected.

Notwithstanding the foregoing, in addition to the rights of the Trustee and the Bondholders to direct proceedings as described above, if a Credit Facility is in effect, for so long as such Credit Facility is outstanding and the Credit Facility Issuer is not in default in its duties under the Indenture or the Credit Facility, the Credit Facility Issuer issuing will have the absolute right to direct all proceedings on behalf of the Bondholders of the Bonds. Additionally, if the Event of Default which has occurred is an Event of Default under paragraphs (e) or (f) above, the Credit Facility Issuer, if any, will have no right to direct the Trustee or the Bondholders with respect to any matters, including remedies, and the holders of a majority in aggregate principal amount of the Bonds then outstanding, will have the right, at any time, by an instrument or instruments in writing executed and delivered to the Trustee, to direct the time, method and place of conducting all proceedings to be taken in connection with the enforcement of the terms and conditions of the Indenture, or for the appointment of a receiver or any other proceedings hereunder; provided, that such direction shall not be otherwise than in accordance with the provisions of law and of the Indenture.

If an Event of Default has occurred under the Indenture due to failure by the Credit Facility Issuer, if any, to honor a properly presented and conforming drawing by the Trustee under the Credit Facility then in effect in accordance with the terms thereof, all obligations of the Trustee to the Credit Facility Issuer and all rights of such Credit Facility Issuer under the Indenture will be suspended until the earlier of the cure of such failure or all of the Bonds have been paid in full.

Waiver of Events of Default

Except as provided below, the Trustee may in its discretion waive any Event of Default under the Indenture and will do so upon the written request of the registered owners holding a majority in principal amount of all Bonds then outstanding. If, after the principal of all Bonds then outstanding have been declared to be due and payable as a result of a default under the Indenture and prior to any judgment or decree for the appointment of a receiver or for the payment of the moneys due has been obtained or entered, (i) the Company causes to be deposited with the Trustee a sum sufficient to pay all matured installments of interest upon all Bonds and the principal of and premium, if any, on any and all Bonds which would become due otherwise than by reason of such declaration (with interest thereon as provided in the Indenture) and the expenses of the Trustee in connection with such default and (ii) all Events of Default under the Indenture (other than nonpayment of the principal of Bonds due by such declaration) have been remedied, then such Event of Default will be deemed waived and such declaration and its consequences rescinded and annulled by the Trustee. Such waiver, rescission and annulment will be binding upon all Bondholders. No such waiver, rescission and annulment will extend to or affect any subsequent Event of Default or impair any right or remedy consequent thereon.

The Trustee may not waive any default under clauses (e) or (f) unless the Trustee has received in writing from the Credit Facility Issuer a written notice of full reinstatement of the full amount of the Credit Facility and a written rescission of the notice of the Event of Default.

Notwithstanding the foregoing, nothing in the Indenture will affect the right of a registered owner to enforce the payment of principal of, premium, if any, and interest on the Bonds after the maturity thereof.

Supplemental Indentures

The Issuer and the Trustee may enter into indentures supplemental to the Indenture without the consent of or notice to the Bondholders in order (i) to cure any ambiguity or formal defect or omission in the Indenture, (ii) to grant to or confer upon the Trustee, as may lawfully be granted, additional rights, remedies, powers or authorities for the benefit of the Bondholders, (iii) to subject to the Indenture additional revenues, properties or collateral, (iv) to permit qualification of the Indenture under any federal statute or state blue sky law, (v) to add additional covenants and agreements of the Issuer for the protection of the Bondholders or to surrender or limit any rights, powers or authorities reserved to or conferred upon the Issuer, (vi) to make any other modification or change to the Indenture which, in the sole judgment of the Trustee, does not adversely affect the Trustee or any Bondholder, (vii) to make other amendments not otherwise permitted by (i), (ii), (iii), (iv) or (vi) of this paragraph to provisions relating to federal income tax matters under the Code or other relevant provisions if, in the opinion of Bond Counsel, those amendments would not adversely affect the exclusion of the interest on the Bonds from gross income for federal income tax purposes, (viii) to make any modifications or changes to the Indenture necessary to provide the securing of a Credit Facility or Alternate Credit Facility or any liquidity or credit support of any kind for the security of the Bonds (including without limitation any line of credit, letter of credit, guaranty agreement or insurance coverage), including any modifications of the Indenture or the Agreement necessary to upgrade or maintain the then applicable ratings on the Bonds or (ix) to permit the issuance of the Bonds in other than book-entry-only form or to provide changes to or for the book-entry system.

Subject to the consent of the Credit Facility Issuer, if any, exclusive of supplemental indentures for the purposes set forth in the preceding paragraph, the consent of registered owners holding a majority in aggregate principal amount of all Bonds then outstanding is required to approve any supplemental indenture, except no such supplemental indenture may permit, without the consent of all of the registered owners of the Bonds then outstanding, (i) an extension of the maturity of the principal of or the interest on any Bond issued under the Indenture or a reduction in the principal amount of any Bond or the rate of interest or time of redemption or redemption premium thereon, (ii) a privilege or priority of any Bond or Bonds over any other Bond or Bonds, (iii) a reduction in the aggregate principal amount of the Bonds required for consent to such supplemental indenture or (iv) the deprivation of any registered owners of the lien of the Indenture.

If at any time the Issuer requests the Trustee to enter into any supplemental indenture requiring the consent of the registered owners of the Bonds, the Trustee, upon being satisfactorily indemnified with respect to expenses, must notify all such registered owners. Such notice must set forth the nature of the proposed supplemental indenture and must state that copies thereof are on file at the principal office of the Trustee for inspection. If, within sixty days (or such longer period as prescribed by the Issuer or the Company) following the mailing of such notice, the registered owners holding the requisite amount of the Bonds outstanding have consented to the execution thereof, no Bondholder will have any right to object or question the execution thereof.

No supplemental indenture will become effective unless the Company consents to the execution and delivery of such supplemental indenture. The Company will be deemed to have consented to the execution and delivery of any supplemental indenture if the Trustee does not receive a notice of protest or objection signed by the Company on or before 4:30 p.m., local time in the city in which the principal office of the Trustee is located, on the fifteenth day after the mailing to the Company of a notice of the proposed changes and a copy of the proposed supplemental indenture.

Notwithstanding the foregoing, any Supplemental Indenture that requires the consent of the Bondholders that (i) is to become effective while a Credit Facility is in place or while any amounts are outstanding under any Reimbursement Agreement and (ii) adversely affects the Credit Facility Issuer will not become effective unless and until the Credit Facility Issuer consents in writing to the execution and delivery of such Supplemental Indenture.

Cancellation of Credit Facility; Delivery of Alternate Credit Facility

The Trustee will, at the written direction of the Company but subject to the conditions described in this paragraph and the receipt of an Opinion of Bond Counsel stating that the cancellation of such Credit Facility is authorized under the Indenture and under the Act and will not adversely affect the exclusion from gross income of interest on the Bonds for federal income tax purposes, cancel any Credit Facility in accordance with the terms thereof which cancellation may be without substitution therefor or replacement thereof; provided, that any such cancellation will not become effective, surrender of such Credit Facility will not take place and that Credit Facility will not terminate, in any event, until (i) payment by the Credit Facility Issuer has been made for any and all drawings by the Trustee effected on or before such cancellation date (including, if applicable, any drawings for payment of the purchase price of Bonds to be purchased pursuant to the Indenture in connection with such cancellation) and (ii) if the Bonds are in an Long Term Rate Period, only if the then current Long Term Rate Period for the Bonds is ending on, or the Bonds are subject to optional redemption on, the Interest Payment Date immediately preceding the date of such cancellation. Upon written notice given by the Company to the Trustee at least 20 days (35 days if the Bonds are bearing interest at the Long Term Rate) prior to the date of cancellation of any Credit Facility of such cancellation and the effective date of such cancellation, the Trustee will surrender such Credit Facility to the Credit Facility Issuer by which it was issued on or promptly after the effective date of such cancellation in accordance with its terms; provided, that such notice will not be given in any event, if the purchase price of any Bonds to be purchased pursuant to the Indenture in connection with such cancellation includes any premium unless the Company has certified in such notice that the Trustee can draw under a Credit Facility (other than any Alternate Credit Facility being delivered in connection with such cancellation) on the purchase date related to such purchase of Bonds in an aggregate amount sufficient to pay the premium due upon such purchase of Bonds on such purchase date.

The Company may, at its option, provide for the delivery to the Trustee of an Alternate Credit Facility in replacement of any Credit Facility then in effect. At least 20 days (35 days if the Interest Rate on the Bonds is a Long Term Rate) prior to the date of delivery of an Alternate Credit Facility to the Trustee, the Company must give notice, which notice will also be given to the Remarketing Agent, of such replacement to the Trustee, together with an Opinion of Bond Counsel to the effect that the delivery of such Alternate Credit Facility to the Trustee is authorized under the Indenture and the Act and complies with the terms thereof and that the delivery of such Alternate Credit Facility will not adversely affect the exclusion from gross income of interest on the Bonds for federal income tax purposes. The Trustee will then accept such Alternate Credit Facility and surrender the previously held Credit Facility, if any, to the previous Credit Facility Issuer for cancellation promptly on or after the 5th day after the Alternate Credit Facility becomes effective; provided, however, that such Alternate Credit Facility must become effective on an Interest Payment Date and, if the Bonds are in a Long Term Rate Period, such Alternate Credit Facility may only become effective on either the last Interest Payment Date for such Long Term Rate Period or an Interest Payment Date on which the Bonds are subject to optional redemption. The notice given to the Trustee shall also be given to the Issuer, the then current Credit Facility Issuer, Moody's, if the Bonds are then rated by Moody's, and S&P, if the Bonds are then rated by S&P; provided that the notice will not be given if the purchase price of any Bonds to be purchased pursuant to the Indenture in connection with such cancellation includes any premium unless the Company has certified in such notice that the Trustee can draw under a Credit Facility then in effect on the purchase date related to such purchase of Bonds in an aggregate amount sufficient to pay the premium due upon such purchase of Bonds on such purchase date and until payment under the Credit Facility to be surrendered shall have been made for any and all drawings by the Trustee effected on or before the date of such surrender for cancellation (including, if applicable, any drawings for payment of the purchase price of Bonds to be purchased pursuant to the Indenture in connection with such cancellation).

Any Alternate Credit Facility delivered to the Trustee must be accompanied by an opinion of counsel to the issuer or provider of such Credit Facility stating that such Credit Facility is a legal, valid, binding and enforceable obligation of such issuer or obligor in accordance with its terms.

The Bonds will be subject to mandatory tender for purchase on the date of cancellation of a Credit Facility and on the date of the delivery of an Alternate Credit Facility. See "Summary of the Bonds — Mandatory Purchases of Bonds."

Enforceability of Remedies

The remedies available to the Trustee, the Issuer and the owners upon an event of default under the Loan Agreement or the Indenture are in many respects dependent upon judicial actions which are often subject to discretion and delay. Under existing constitutional and statutory law and judicial decisions, the remedies specified by the Loan Agreement or the Indenture may not be readily available or may be limited. The various legal opinions to be delivered concurrently with the delivery of the Bonds will be qualified as to the enforceability of the various legal instruments by limitations imposed by principles of equity, bankruptcy, reorganization, insolvency, moratorium or other similar laws affecting the rights of creditors generally.

Reoffering

Subject to the terms and conditions of the Remarketing and Bond Purchase Agreement (the "Remarketing Agreement"), between the Company and Banc of America Securities LLC, as Remarketing Agent, the Remarketing Agent has agreed to purchase and reoffer the Bonds delivered to the Paying Agent for purchase, at a price equal to 100% of the principal amount of the Bonds, plus accrued interest (if any), and in connection therewith will receive compensation in the amount of $135,000, plus reimbursement of certain expenses. Under the terms of the Remarketing Agreement, the Company has agreed to indemnify the Remarketing Agent against certain civil liabilities, including liabilities under federal securities laws.

In the ordinary course of its business, the Remarketing Agent and certain of its affiliates, have engaged, and may in the future engage, in investment banking or commercial banking transactions with the Company.

Tax Treatment

On each of February 23, 2007, the date of original issuance and delivery of the 2006 Series B Bonds, and October 17, 2008, the date of original issuance and delivery of the 2008 Series A Bonds, Bond Counsel delivered its opinions stating that under existing law, including current statutes, regulations, administrative rulings and official interpretations, subject to the qualifications and exceptions set forth below, interest on the Bonds would be excluded from the gross income of the recipients thereof for federal income tax purposes, except that no opinion would be expressed regarding such exclusion from gross income with respect to any Bond during any period in which it is held by a "substantial user" of the applicable Project or a "related person" as such terms are used in Section 147(a) of the Code. Interest on the Bonds will be an item of tax preference in determining alternative minimum taxable income for individuals and corporations under the Code. Bond Counsel further opined that, subject to the assumptions stated in the preceding sentence, (i) interest on the Bonds would be excluded from gross income of the owners thereof for Kentucky income tax purposes and (ii) the Bonds would be exempt from all ad valorem taxes in Kentucky. Such opinions have not been updated as of the date hereof and no continuing tax exemption opinions are expressed by Bond Counsel.

Bond Counsel also will deliver opinions in connection with this reoffering to the effect that the conversion of the interest rate on the Bonds to the Weekly Rate and the delivery of the Letter of Credit (i) is authorized or permitted by Sections 103.200 to 103.285, inclusive, of the Kentucky Revised Statutes (the "Act") and the Indenture and (ii) will not adversely affect the validity of the Bonds or any exclusion from gross income of interest on the Bonds for federal income tax purposes to which interest on the Bonds would otherwise be entitled.

The opinions of Bond Counsel as to the excludability of interest from gross income for federal income tax purposes were based upon and assumed the accuracy of certain representations of facts and circumstances, including with respect to the Projects, which were within the knowledge of the Company and compliance by the Company with certain covenants and undertakings set forth in the proceedings authorizing the Bonds which are intended to assure that the Bonds are and will remain obligations the interest on which is not includable in gross income of the recipients thereof under the law in effect on the date of such opinion. Bond Counsel did not independently verify the accuracy of the certifications and representations made by the Company and the Issuer. On the date of the applicable opinions and subsequent to the original delivery of the 2006 Series B Bonds on February 23, 2007 and the 2008 Series A Bonds on October 17, 2008, as applicable, such representations of facts and circumstances must be accurate and such covenants and undertakings must continue to be complied with in order that interest on the Bonds be and remain excludable from gross income of the recipients thereof for federal income tax purposes under existing law. Bond Counsel expressed no opinion (i) regarding the exclusion of interest on any Bond from gross income for federal income tax purposes on or after the date on which any change, including any interest rate conversion, permitted by the documents other than with the approval of Bond Counsel is taken which adversely affects the tax treatment of the Bonds or (ii) as to the treatment for purposes of federal income taxation of interest on the Bonds upon a Determination of Taxability.

Bond Counsel further opined that the Code prescribed a number of qualifications and conditions for the interest on state and local government obligations to be and to remain excluded from gross income for federal income tax purposes, some of which, including provisions for potential payments by the Issuers to the federal government, require future or continued compliance after issuance of the Bonds in order for the interest to be and to continue to be so excluded from the date of issuance. Noncompliance with certain of these requirements by the Company or the Issuer with respect to the Bonds could cause the interest on the Bonds to be included in gross income for federal income tax purposes and to be subject to federal income taxation retroactively to the date of their issuance. The Company and the Issuer each covenanted to take all actions required of each to assure that the interest on the Bonds shall be and remain excluded from gross income for federal income tax purposes, and not to take any actions that would adversely affect that exclusion.

The opinions of Bond Counsel as to the exclusion of interest on the Bonds from gross income for federal income tax purposes and federal tax treatment of interest on the Bonds was subject to the following exceptions and qualifications:

(a) The Code provides for a "branch profits tax" which subjects to tax, at a rate of 30%, the effectively connected earnings and profits of a foreign corporation which engages in a United States trade or business. Interest on the Bonds would be includable in the amount of effectively connected earnings and profits and thus would increase the branch profits tax liability.

(b) The Code also provides that passive investment income, including interest on the Bonds, may be subject to taxation for any S corporation with Subchapter C earnings and profits at the close of its taxable year if greater than 25% of its gross receipts is passive investment income.

Except as stated above, Bond Counsel expressed no opinion as to any federal or Kentucky tax consequences resulting from the receipt of interest on the Bonds.

Owners of the Bonds should be aware that the ownership of the Bonds may result in collateral federal income tax consequences. For instance, the Code provides that property and casualty insurance companies will be required to reduce their loss reserve deductions by 15% of the tax-exempt interest received on certain obligations, such as the Bonds, acquired after August 7, 1986. (For purposes of the immediately preceding sentence, a portion of dividends paid to an affiliated insurance company may be treated as tax-exempt interest.) The Code further provides for the disallowance of any deduction for interest expenses incurred by banks and certain other financial institutions allocable to carrying certain tax-exempt obligations, such as the Bonds, acquired after August 7, 1986. The Code also provides that, with respect to taxpayers other than such financial institutions, such taxpayers will be unable to deduct any portion of the interest expenses incurred or continued to purchase or carry the Bonds. The Code also provides, with respect to individuals, that interest on tax-exempt obligations, including the Bonds, is included in modified adjusted gross income for purposes of determining the taxability of social security and railroad retirement benefits. Furthermore, the earned income tax credit is not allowed for individuals with an aggregate amount of disqualified income within the meaning of Section 32 of the Code, which exceeds $2,200. Interest on the Bonds will be taken into account in the calculation of disqualified income. Prospective purchasers of the Bonds should consult their own tax advisors regarding such matters and any other tax consequences of holding the Bonds.

From time to time, there are legislative proposals in Congress which, if enacted, could alter or amend one or more of the federal tax matters referred to above or could adversely affect the market value of the Bonds. It cannot be predicted whether or in what form any such proposal might be enacted or whether, if enacted, it would apply to obligations (such as the Bonds) issued prior to enactment.

The opinions of Bond Counsel relating to conversion of the Bonds in substantially the forms in which they are expected to be delivered on the Conversion Date, redated to the Conversion Date, are attached as Appendices B-3 and B-4.

Legal Matters

Certain legal matters in connection with the Conversion and reoffering of the Bonds will be passed upon by Stoll Keenon Ogden, Bond Counsel. Bond Counsel has in the past, and may in the future, act as counsel to the Company with respect to certain matters. Certain legal matters will be passed upon for the Issuer by its County Attorney. Certain legal matters will be passed upon for the Company by Jones Day, Chicago, Illinois, and John R. McCall, Esq., Executive Vice President, General Counsel, Corporate Secretary and Chief Compliance Officer for the Company. Winston & Strawn LLP, Chicago, Illinois, will pass upon certain legal matters for the Remarketing Agent.

Continuing Disclosure

Because the Bonds are special and limited obligations of the Issuer, the Issuer is not an "obligated person" for purposes of Rule 15c2-12 (the "Rule") promulgated by the SEC under the Exchange Act, and does not have any continuing obligations thereunder. Accordingly, the Issuer will not provide any continuing disclosure information with respect to the Bonds or the Issuer.

2006 Series B Bonds

In order to enable the Remarketing Agent to comply with the requirements of the Rule, the Company has covenanted in a continuing disclosure undertaking agreement delivered to the Trustee for the benefit of the holders of the 2006 Series B Bonds (the "Continuing Disclosure Agreement") to provide certain continuing disclosure for the benefit of the holders of such Bonds. Under its Continuing Disclosure Agreement, the Company has covenanted to take the following actions:

(a) The Company will provide to each nationally recognized municipal securities information repository ("NRMSIR"), recognized by the SEC pursuant to the Rule, and the state information depository, if any, of the Commonwealth of Kentucky (a "SID" and, together with the NRMSIR, a "Repository") recognized by the SEC (1) annual financial information of the type set forth in Appendix A to this Reoffering Circular (including any information incorporated by reference therein) and (2) audited financial statements prepared in accordance with generally accepted accounting principles, in each case not later than 120 days after the end of the Company's fiscal year.

(b) The Company will file in a timely manner with each NRMSIR or the Municipal Securities Rulemaking Board, and with the SID, if any, notice of the occurrence of any of the following events (if applicable) with respect to the 2006 Series B Bonds, if material: (i) principal and interest payment delinquencies; (ii) non-payment related defaults; (iii) any unscheduled draws on debt service reserves reflecting financial difficulties; (iv) unscheduled draws on credit enhancement facilities reflecting financial difficulties; (v) substitution of credit or liquidity providers, or their failure to perform; (vi) adverse tax opinions or events affecting the tax-exempt status of the 2006 Series B Bonds; (vii) modifications to rights of the holders of the 2006 Series B Bonds; (viii) the giving of notice of optional or unscheduled redemption of any 2006 Series B Bonds; (ix) defeasance of the 2006 Series B Bonds or any portion thereof; (x) release, substitution, or sale of property securing repayment of the 2006 Series B Bonds; and (xi) rating changes with respect to the 2006 Series B Bonds or the Company or any obligated person, within the meaning of the Rule.

(c) The Company will file in a timely manner with each Repository notice of a failure by the Company to file any of the notices or reports referred to in paragraphs (a) and (b) above by the due date.

The Company may amend its Continuing Disclosure Agreement (and the Trustee shall agree to any amendment so requested by the Company that does not change the duties of the Trustee thereunder) or waive any provision thereof, but only with a change in circumstances that arises from a change in legal requirements, change in law, or change in the nature or status of the Company with respect to the 2006 Series B Bonds or the type of business conducted by the Company; provided that the undertaking, as amended or following such waiver, would have complied with the requirements of the Rule on the date of issuance of the 2006 Series B Bonds, after taking into account any amendments to the Rule as well as any change in circumstances, and the amendment or waiver does not materially impair the interests of the holders of the 2006 Series B Bonds to which such undertaking relates, in the opinion of the Trustee or counsel expert in federal securities laws acceptable to both the Company and the Trustee, or is approved by the Beneficial Owners of a majority in aggregate principal amount of the outstanding 2006 Series B Bonds. The Company acknowledges that its undertakings pursuant to the Rule described under this heading are intended to be for the benefit for the holders of the 2006 Series B Bonds and shall be enforceable by the holders of those 2006 Series B Bonds or by the Trustee on behalf of such holders. Any breach by the Company of these undertakings pursuant to the Rule will not constitute an event of default under the Indentures, the Loan Agreements or the 2006 Series B Bonds.

2008 Series A Bonds

The Rule generally requires that "obligated persons" such as the Company agree to provide (i) continuing disclosure on an annual basis of certain financial information and operating data and (ii) notices of certain specified events that could affect the credit underlying the payment obligations of the securities. However, offerings of securities that are subject purchase by the issuer on the demand of the holder, such as will be the case with respect to the 2008 Series A Bonds while bearing interest in a Daily Rate Period or a Weekly Rate Period, or while bearing interest in a Flexible Rate Period of 270 days or less, are exempt from these requirements. If the 2008 Series A Bonds are remarketed in a mode other than the Daily Rate Period, the Weekly Rate Period or the Flexible Rate Period, the Company may in the future become subject to these continuing disclosure obligations of the Rule with respect to such 2008 Series A Bonds.

This Reoffering Circular has been duly approved, executed and delivered by the Company.

KENTUCKY UTILITIES COMPANY

By: /s/ Daniel K. Arbough
Daniel K. Arbough
Treasurer

Appendix A

Kentucky Utilities Company –

Financial Statements and Additional Information

This Appendix A includes the Selected Financial Data presented below, as well as the (i) Financial Statements and Additional Information (Unaudited) As of September 30, 2008 and December 31, 2007 and for the three-month and nine-month periods ended September 30, 2008 and 2007 (the "Quarterly Report") and (ii) Financial Statements and Additional Information As of December 31, 2007 and 2006 (the "Annual Report").

The information contained in this Appendix A relates to and has been obtained from Kentucky Utilities Company ("KU") and from other sources as shown herein. The delivery of the Reoffering Circular shall not create any implication that there has been no change in the affairs of KU since the date hereof, or that the information contained or incorporated by reference in this Appendix A is correct at any time subsequent to its date.

Kentucky Utilities Company

KU, incorporated in Kentucky in 1912 and in Virginia in 1991, is a regulated public utility engaged in the generation, transmission, distribution and sale of electric energy in Kentucky, Virginia and Tennessee. As of September 30, 2008, KU provided electricity to approximately 507,000 customers in 77 counties in central, southeastern and western Kentucky, approximately 30,000 customers in 5 counties in southwestern Virginia and 5 customers in Tennessee. KU's service area covers approximately 6,600 square miles. KU's coal-fired electric generating stations produce most of KU's electricity. The remainder is generated by a hydroelectric power plant and natural gas and oil fueled combustion turbines. In Virginia, KU operates under the name Old Dominion Power Company. KU also sells wholesale electric energy to 12 municipalities.

KU is a wholly-owned subsidiary of E.ON U.S., an indirect wholly-owned subsidiary of E.ON, a German corporation, making KU an indirect wholly-owned subsidiary of E.ON. KU's affiliate, Louisville Gas and Electric Company, is a regulated public utility engaged in the generation, transmission, distribution and sale of electric energy and the distribution of natural gas in Kentucky.

Recent Developments

Brown New Source Review Litigation. As disclosed in Note 7 to Notes to Financial Statements (Unaudited) As of September 30, 2008 and December 31, 2007 and for the three-month and nine-month periods ended September 30, 2008 and 2007, in April 2006, the EPA issued an NOV alleging that KU had violated certain provisions of the Clean Air Act's new source review rules and new source performance standards relating to work performed in 1997 on a boiler and turbine at Unit 3 at KU's E.W. Brown generating station. In December 2006, the EPA issued a second NOV alleging the Company had exceeded heat input values in violation of air permits for

Unit 3. In March 2007, the U.S. Department of Justice filed a complaint in federal court in Kentucky alleging the same violations specified in the prior NOVs. The complaint seeks civil penalties, including potential per-day fines, remedial measures and injunctive relief. In April 2007, KU filed an answer in the civil suit denying the allegations. In July 2007, the court entered a schedule providing for a July 2009 date for trial. As of September 30, 2008, a \$3.2 million accrual was recorded based on the then current status of settlement discussions.

KU, the EPA and the Department of Justice have reached a tentative agreement in principle on a proposed settlement of the lawsuit and the NOVs, the terms of which include:

- Payment of a \$1.4 million civil penalty
- Establishment of \$3 million fund for environmental mitigation projects that will include carbon sequestration testing and school bus retrofits
- Surrender of 53,000 SO_2 allowances
- Surrender of excess NO_x allowances for Brown Unit 3 through 2020
- Installation of flue gas desulfurization ("FGD") controls at Brown Unit 3 by December 31, 2010
- Installation of selective catalytic reduction ("SCR") controls at Brown Unit 3 by December 31, 2012
- Compliance with specified operational restrictions, including NO_x, SO_2 and particulate matter emission limits and heat input limits

Capital expenditures associated with installation of the FGD and SCR controls at Unit 3 are currently estimated to be approximately \$585 million, of which \$109 million had been spent through December 31, 2007 and \$295 million had been included in KU's previously disclosed capital expenditures for the three years ended December 31, 2010. Funding for these capital expenditures is expected to be provided by borrowings from affiliates. KU currently expects that the capital expenditures associated with the installation of the FGD and SCR controls and any additional operating costs resulting from the surrender of SO_2 or NO_x allowances will be recoverable through existing regulatory recovery mechanisms. The terms of the proposed settlement are not expected to have a material adverse effect on KU's financial condition or results of operations or on KU's ability to operate its plants.

Final settlement of the lawsuit and the NOVs is subject to approval by the board of directors, the EPA and the Department of Justice, execution of a consent decree and approval of the consent decree by the U.S. District Court for the Eastern District of Kentucky. There is no guarantee that the proposed settlement will be executed and approved on the terms outlined above, or at all. If the proposed settlement is not approved, KU cannot predict the ultimate outcome of these proceedings, including whether fines, penalties or remedial measures significantly more burdensome than those outlined above may result.

Selected Financial Data

(in millions)	Twelve Months Ended September 30, 2008 (1)	Years Ended December 31, 2007	2006	2005	2004	2003
Operating revenues	$1,349	$1,273	$1,210	$1,207	$ 995	$ 892
Net operating income	$ 249	$ 268	$ 235	$ 202	$ 228	$ 162
Net income	$ 154	$ 167	$ 152	$ 112	$ 134	$ 91
Total assets	$4,244	$3,796	$3,143	$2,756	$2,610	$2,505
Long-term obligations (including amounts due within one year)	$1,359	$1,264	$ 843	$ 746	$ 726	$ 688
Ratio of Earnings to Fixed Charges (2)	4.08x	5.13x	6.77x	6.41x	8.85x	6.62x

Capitalization:	September 30, 2008	% of Capitalization
Long-Term Debt	$1,326	44.16%
Common Equity	$1,677	55.84%
Total Capitalization	$3,003	100.00%

(1) The figures listed in the column titled "12 Months Ended September 30, 2008" were calculated by subtracting from the 12 months ended December 31, 2007 financial statements, the amounts from financial statements for the nine months ended September 30, 2007, and then adding the amounts from financial statements for the nine months ended September 30, 2008.

(2) For purposes of this ratio, "Earnings" consist of the aggregate of Income Before Cumulative Effect of a Change in Accounting Principle, taxes on income, investment tax credit (net) and "Fixed Charges." "Fixed Charges" consist of interest charges and one-third of rentals charged to operating expenses.

Management's Discussion and Analysis in the Quarterly Report and the Annual Report, as well as the Notes to Financial Statements as of December 31, 2007 and 2006 and the Notes to Financial Statements (Unaudited) As of September 30, 2008 and December 31, 2007 and for the three-month and nine-month periods ended September 30, 2008 and 2007 should be read in conjunction with the above information.

Kentucky Utilities Company

Financial Statements and Additional Information

(Unaudited)

As of September 30, 2008 and December 31, 2007
and for the three-month and nine-month periods ended
September 30, 2008 and 2007

INDEX OF ABBREVIATIONS

ARO	Asset Retirement Obligation
BART	Best Available Retrofit Technology
CAIR	Clean Air Interstate Rule
CAMR	Clean Air Mercury Rule
CAVR	Clean Air Visibility Rule
CCN	Certificate of Public Convenience and Necessity
Clean Air Act	The Clean Air Act, as amended in 1990
CMRG	Carbon Management Research Group
Company	Kentucky Utilities Company
DSM	Demand Side Management
ECR	Environmental Cost Recovery
EEI	Electric Energy, Inc.
E.ON	E.ON AG
E.ON U.S.	E.ON U.S. LLC. (formerly LG&E Energy LLC and LG&E Energy Corp.)
E.ON U.S. Services	E.ON U.S. Services Inc. (formerly LG&E Energy Services Inc.)
EPA	U.S. Environmental Protection Agency
EPAct 2005	Energy Policy Act of 2005
EUSIC	E.ON US Investments Corp.
FAC	Fuel Adjustment Clause
FASB	Financial Accounting Standards Board
FERC	Federal Energy Regulatory Commission
FGD	Flue Gas Desulfurization
Fidelia	Fidelia Corporation (an E.ON affiliate)
FIN	FASB Interpretation
GHG	Greenhouse Gas
IRS	Internal Revenue Service
KCCS	Kentucky Consortium for Carbon Storage
KDAQ	Kentucky Division for Air Quality
Kentucky Commission	Kentucky Public Service Commission
KU	Kentucky Utilities Company
kWh	Kilowatt Hours
LG&E	Louisville Gas and Electric Company
MISO	Midwest Independent Transmission System Operator, Inc.
MMBtu	Million British Thermal Units
Moody's	Moody's Investor Services, Inc.
NAAQS	National Ambient Air Quality Standards
NERC	North American Electric Reliability Corporation
NOV	Notice of Violation
NOx	Nitrogen Oxide
OMU	Owensboro Municipal Utilities
PUHCA 2005	Public Utility Holding Company Act of 2005
RRO	Regional Reliability Organization
S&P	Standard & Poor's Rating Service
SCR	Selective Catalytic Reduction
SERC	SERC Reliability Corporation
SFAS	Statement of Financial Accounting Standards
SIP	State Implementation Plan
SO_2	Sulfur Dioxide
TC2	Trimble County Unit 2
VDT	Value Delivery Team Process
Virginia Commission	Virginia State Corporation Commission

TABLE OF CONTENTS

Financial Statements (Unaudited)

Kentucky Utilities Company
Statements of Income
(Unaudited)
(Millions of $)

	Three Months Ended September 30, 2008	Three Months Ended September 30, 2007	Nine Months Ended September 30, 2008	Nine Months Ended September 30, 2007
OPERATING REVENUES:				
Total operating revenues	$ 371	$ 345	$ 1,039	$ 963
OPERATING EXPENSES:				
Fuel for electric generation	147	138	380	354
Power purchased	54	39	164	129
Other operation and maintenance expenses	67	62	208	184
Depreciation and amortization	36	31	99	89
Total operating expenses	304	270	851	756
OPERATING INCOME	67	75	188	207
Other expense (income) – net	(13)	(7)	(31)	(23)
Interest expense (Notes 5 and 6)	3	3	10	11
Interest expense to affiliated companies (Note 8)	15	11	41	29
INCOME BEFORE INCOME TAXES	62	68	168	190
Federal and state income taxes (Note 5)	19	18	51	60
NET INCOME	$ 43	$ 50	$ 117	$ 130

The accompanying notes are an integral part of these financial statements.

Statements of Retained Earnings
(Unaudited)
(Millions of $)

	Three Months Ended September 30, 2008	Three Months Ended September 30, 2007	Nine Months Ended September 30, 2008	Nine Months Ended September 30, 2007
Balance at beginning of period	$ 1,111	$ 950	$ 1,037	$ 870
Net income	43	50	117	130
Balance at end of period	$ 1,154	$ 1,000	$ 1,154	$ 1,000

The accompanying notes are an integral part of these financial statements.

Kentucky Utilities Company
Balance Sheets
(Unaudited)
(Millions of $)

ASSETS	September 30, 2008	December 31, 2007
Current assets:		
Cash and cash equivalents	$ 2	$ -
Restricted cash	1	11
Accounts receivable – less reserves of $3 million and $2 million as of September 30, 2008 and December 31, 2007, respectively	176	172
Accounts receivable from affiliated companies (Note 8)	8	17
Materials and supplies:		
Fuel (predominantly coal)	59	42
Other materials and supplies	36	34
Prepayments and other current assets	3	12
Total current assets	285	288
Other property and investments	33	29
Utility plant:		
At original cost	5,459	4,939
Less: reserve for depreciation	1,705	1,622
Net utility plant	3,754	3,317
Deferred debits and other assets:		
Regulatory assets (Note 2):		
Pension and postretirement benefits	28	28
Other	96	86
Cash surrender value of key man life insurance	38	37
Other assets	10	11
Total deferred debits and other assets	172	162
Total assets	$ 4,244	$ 3,796

The accompanying notes are an integral part of these financial statements.

Kentucky Utilities Company
Balance Sheets (cont.)
(Unaudited)
(Millions of $)

LIABILITIES AND EQUITY	September 30, 2008	December 31, 2007
Current liabilities:		
Current portion of long-term debt (Note 6)	$ 33	$ 33
Notes payable to affiliated companies (Notes 6 and 8)	116	23
Accounts payable	141	160
Accounts payable to affiliated companies (Note 8)	41	48
Customer deposits	20	20
Other current liabilities	31	28
Total current liabilities	382	312
Long-term debt:		
Long-term debt (Note 6)	220	300
Long-term debt to affiliated company (Notes 6 and 8)	1,106	931
Total long-term debt	1,326	1,231
Deferred credits and other liabilities:		
Accumulated deferred income taxes (Note 5)	284	285
Accumulated provision for pensions and related benefits (Note 4)	88	83
Investment tax credit (Note 5)	77	55
Asset retirement obligation	32	30
Regulatory liabilities (Note 2):		
Accumulated cost of removal of utility plant	323	310
Deferred income taxes - net	17	22
Other	18	10
Other liabilities	20	23
Total deferred credits and other liabilities	859	818
Common equity:		
Common stock, without par value –		
Authorized 80,000,000 shares, outstanding 37,817,878 shares	308	308
Additional paid-in capital	215	90
Retained earnings	1,129	1,016
Undistributed subsidiary earnings	25	21
Total retained earnings	1,154	1,037
Total common equity	1,677	1,435
Total liabilities and equity	$ 4,244	$ 3,796

The accompanying notes are an integral part of these financial statements.

Kentucky Utilities Company
Statements of Cash Flows
(Unaudited)
(Millions of $)

	For the Nine Months Ended September 30, 2008	2007
CASH FLOWS FROM OPERATING ACTIVITIES:		
Net income	$ 117	$ 130
Items not requiring cash currently:		
Depreciation and amortization	99	89
Deferred income taxes – net	(3)	(2)
Investment tax credit – net	22	28
Other	2	2
Changes in current assets and liabilities:		
Accounts receivable	4	(1)
Material and supplies	(19)	15
Accounts payable	15	(22)
Prepayments and other current assets	-	9
Other current liabilities	4	(3)
Pension funding	(2)	(13)
Fuel adjustment clause receivable, net	4	(22)
Other	0	(1)
Net cash provided by operating activities	243	209
CASH FLOWS FROM INVESTING ACTIVITIES:		
Construction expenditures	(554)	(512)
Asset transferred from affiliate (Note 8)	(10)	-
Change in restricted cash	10	(17)
Net cash used for investing activities	(554)	(529)
CASH FLOWS FROM FINANCING ACTIVITIES:		
Retirement of first mortgage bonds	-	(107)
Issuance of pollution control bonds	-	81
Additional paid-in capital	125	55
Long-term borrowings from affiliated company (Note 6)	175	278
Short-term borrowings from affiliated company – net (Note 6)	93	8
Reacquired bonds	(80)	-
Net cash provided by financing activities	313	315
CHANGE IN CASH AND CASH EQUIVALENTS	2	(5)
CASH AND CASH EQUIVALENTS AT BEGINNING OF PERIOD	-	6
CASH AND CASH EQUIVALENTS AT END OF PERIOD	$ 2	$ 1

The accompanying notes are an integral part of these financial statements.

Kentucky Utilities Company
Notes to Financial Statements
(Unaudited)

Note 1 - General

The unaudited financial statements include the accounts of the Company. KU's common stock is wholly-owned by E.ON U.S., an indirect wholly-owned subsidiary of E.ON. In the opinion of management, the unaudited interim financial statements include all adjustments, consisting only of normal recurring adjustments, necessary for a fair statement of financial position, results of operations, retained earnings and cash flows for the periods indicated. Certain information and footnote disclosures normally included in financial statements prepared in accordance with generally accepted accounting principles have been condensed or omitted. These unaudited financial statements and notes should be read in conjunction with the Company's financial statements and additional information for the year ended December 31, 2007, including the audited financial statements and notes therein.

Certain reclassification entries have been made to the previous years' financial statements to conform to the 2008 presentation with no impact on net assets, liabilities and capitalization or previously reported net income and cash flows.

RECENT ACCOUNTING PRONOUNCEMENTS

SFAS No. 161

In March 2008, the FASB issued SFAS No. 161, *Disclosures about Derivative Instruments and Hedging Activities, an amendment of FASB Statement No. 133,* which is effective for fiscal years, and interim periods within those fiscal years, beginning on or after November 15, 2008. The objective of this statement is to enhance the current disclosure framework in SFAS No. 133, *Accounting for Derivative Instruments and Hedging Activities, as amended.* The Company is currently evaluating the impact of adoption of SFAS No. 161 on its statements of operations, financial position and cash flows.

SFAS No. 160

In December 2007, the FASB issued SFAS No. 160, *Noncontrolling Interests in Consolidated Financial Statements,* which is effective for fiscal years, and interim periods within those fiscal years, beginning on or after December 15, 2008. The objective of this statement is to improve the relevance, comparability and transparency of financial information in a reporting entity's consolidated financial statements. The Company expects the adoption of SFAS No. 160 to have no impact on its statements of operations, financial position and cash flows.

SFAS No. 159

In February 2007, the FASB issued SFAS No. 159, *The Fair Value Option for Financial Assets and Financial Liabilities – Including an Amendment of FASB Statement No. 115.* SFAS No. 159 permits entities to choose to measure many financial instruments and certain other assets and liabilities at fair value on an instrument-by-instrument basis (the fair value option). Unrealized gains and losses on items for which the fair value option has been elected are to be recognized in earnings at each subsequent reporting date. SFAS No. 159 is effective for fiscal years beginning after November 15, 2007. SFAS No. 159 was adopted effective January 1, 2008 and the Company elected not to fair value its eligible financial assets and liabilities.

SFAS No. 157

In September 2006, the FASB issued SFAS No. 157, *Fair Value Measurements*, which, except as described below, is effective for fiscal years beginning after November 15, 2007. This statement defines fair value, establishes a framework for measuring fair value in generally accepted accounting principles and expands disclosures about fair value measurements. SFAS No. 157 does not expand the application of fair value accounting to new circumstances. In February 2008, the FASB issued FASB Staff Position 157-2, *Effective Date of FASB Statement No. 157,* which delays the effective date of SFAS No. 157 for all nonfinancial assets and liabilities, except those that are recognized or disclosed at fair value in the financial statements on a recurring basis (at least annually), to fiscal years beginning after November 15, 2008, and interim periods within those fiscal years. All other amendments related to SFAS No. 157 have been evaluated and have no impact on the Company's financial statements. SFAS No. 157 was adopted effective January 1, 2008, except as it applies to those nonfinancial assets and liabilities, and had no impact on the statements of operations, financial position and cash flows, however, additional disclosures relating to its financial derivatives and AROs, as required, are now provided.

Note 2 - Rates and Regulatory Matters

For a description of each line item of regulatory assets and liabilities, reference is made to KU's Annual Report, Note 2 of the financial statements, for the year ended December 31, 2007.

The following regulatory assets and liabilities were included in KU's Balance Sheets:

Kentucky Utilities Company
(unaudited)

(in millions)	September 30, 2008	December 31, 2007
ARO	$ 27	$ 24
Unamortized loss on bonds	12	10
MISO exit	19	20
FAC	14	17
ECR	19	11
Other	5	4
Subtotal	96	86
Pension and postretirement benefits	28	28
Total regulatory assets	$ 124	$ 114
Accumulated cost of removal of utility plant	$ 323	$ 310
Deferred income taxes – net	17	22
Other	18	10
Total regulatory liabilities	$ 358	$ 342

KU does not currently earn a rate of return on the FAC regulatory asset, which is a separate recovery mechanism with recovery within twelve months. No return is earned on the pension and postretirement benefits regulatory asset that represents the changes in funded status of the plans. KU is seeking recovery of this asset with the Kentucky Commission as part of the current base rate case and will seek recovery of this asset in future proceedings with the Virginia Commission. No return is currently earned on the ARO asset. This regulatory asset will be offset against the associated regulatory liability, ARO asset and ARO liability at the time the underlying asset is retired. The MISO exit amount represents the costs relating to the withdrawal from MISO membership. KU is seeking recovery of this asset with the Kentucky Commission as part of the current base rate case and will seek recovery of this asset in future proceedings with the Virginia Commission. KU currently earns a rate of return on the remaining regulatory assets. Other regulatory assets include the merger surcredit and deferred storm costs. Other regulatory liabilities include DSM and MISO costs currently included in base rates that will be netted against costs of withdrawing from the MISO in the next base rate case.

MISO Exit. KU and the MISO have agreed upon overall calculation methods for the contractual exit fee to be paid by the Company following its withdrawal. In October 2006, KU paid $20 million to the MISO pursuant to an invoice regarding the exit fee and made related FERC compliance filings. The Company's payment of this exit fee amount was with reservation of its rights to contest the amount, or components thereof, following a continuing review of its calculation and supporting documentation. KU and the MISO resolved their dispute regarding the calculation of the exit fee and, in November 2007, filed an application with the FERC for approval of a recalculation agreement. In March 2008, the FERC approved the parties' recalculation of the exit fee, and the approved agreement provided KU with an immediate recovery of $1 million and will provide an estimated $3 million over the next eight years for credits realized from other payments the MISO will receive, plus interest. Orders of the Kentucky Commission approving the Company's exit from the MISO have authorized the establishment of a regulatory asset for the exit fee, subject to adjustment for possible future MISO credits, and a regulatory liability for certain revenues associated with former MISO administrative charges, which continue to be collected via base rates. The treatment of the regulatory asset and liability will be determined in KU's base rate case, for which a hearing is scheduled for KU's Kentucky base rate case beginning on January 13, 2009. The Company historically has received approval to recover and refund regulatory assets and liabilities.

FAC. In August 2008, the Kentucky Commission initiated a routine examination of KU's FAC for the six-month period November 1, 2007 through April 30, 2008. A hearing was held on October 7, 2008. A second hearing has been scheduled for November 25, 2008, for the sole purpose of hearing public comments, if any, from several counties in which the newspapers failed to publish notice as requested in a timely manner. An order is expected in December of 2008 or the first quarter of 2009.

In January 2008, the Kentucky Commission initiated a routine examination of KU's FAC for the six-month period May 1, 2007 through October 31, 2007. The Kentucky Commission issued an Order in June 2008, approving the charges and credits billed through the FAC during the review period.

In August 2007, the Kentucky Commission initiated a routine examination of KU's FAC for the six-month period of November 1, 2006 through April 30, 2007. The Kentucky Commission issued an Order in January 2008, approving the charges and credits billed through the FAC during the review period.

KU also employs an FAC mechanism for Virginia customers using an average fuel cost factor based primarily on projected fuel costs. The factor may be adjusted annually for over- or under-collections of fuel costs from the prior year. In February 2008, KU filed an application with the Virginia Commission seeking approval of a decrease in its fuel cost factor applicable during the billing period, April 2008 through March 2009. The Virginia Commission allowed the new rates to be in effect for the April 2008 customer billings. In April 2008, the Virginia Commission Staff recommended a change to the fuel factor KU filed in its application, to which KU has agreed. Following a public hearing and an Order in May 2008, the recommended change became effective in June 2008, resulting in a decrease of 0.482 cents/kWh from the factor in effect for the April 2007 through March 2008 period.

ECR. In June 2008, the Kentucky Commission initiated two six-month reviews for periods ending October 31, 2007 and April 30, 2008, of KU's environmental surcharge. The Kentucky Commission issued an Order in August 2008, approving the charges and credits billed through the ECR during the review period and the rate of return on capital.

In September 2007, the Kentucky Commission initiated six-month and two-year reviews for periods ending October 31, 2006 and April 30, 2007, respectively, of KU's environmental surcharge. The Kentucky Commission issued final Orders in March 2008, approving the charges and credits billed through the ECR during the review periods, as well as approving billing adjustments, roll-in adjustments to base rates, revisions to the monthly surcharge filing and the rates of return on capital.

Other Regulatory Matters

Hurricane Ike Wind Storm. In September 2008, high winds from the remnants of the Hurricane Ike wind storm passed through KU's service territory causing significant outages and system damage. In October 2008, KU filed an application with the Kentucky Commission requesting approval to establish a regulatory asset, and defer for future recovery, $3 million of expenses related to the storm restoration. An order has been requested by the end of the year.

Base Rate Case. In July 2008, KU filed an application with the Kentucky Commission requesting increases in base electric rates of 2.0% or $22 million annually. A hearing is scheduled beginning on January 13, 2009. The requested rates have been suspended until February 5, 2009, at which time they may be put into effect, subject to refund, if the Kentucky Commission has not issued an order in the proceeding. In conjunction with the filing of the application for a change in base rates, based on previous orders by the Kentucky Commission approving settlement agreements among all interested parties, the VDT surcredit terminated in August 2008, and the merger surcredit will terminate upon the implementation of new base rates. The termination of the VDT surcredit and merger surcredit will result in a $16 million increase in revenues annually.

FERC Wholesale Rate Case. In September 2008, KU filed an application with the FERC for increases in base electric rates applicable to wholesale power sales contracts or interchange agreements involving, collectively, twelve Kentucky municipalities. The application requests a shift from current, all-in stated unit charge rates to an unbundled and formula rate. The revised rates represent an increase of 6% to 7% of current charges and requests a change from the all-in stated applicable return on equity of 12%. The proceeding involves data requests or hearings before the FERC, as well as data requests and filings by intervenors. An order in the proceeding may occur in early 2009.

CMRG and KCCS Contributions. In July 2008, KU and LG&E, along with Duke Energy Kentucky, Inc. and Kentucky Power Company, filed an application with the Kentucky Commission requesting approval to establish regulatory assets related to contributions to the CMRG for the development of technologies for reducing carbon dioxide emissions and the KCCS to study the feasibility of geologic storage of carbon dioxide. The filing companies proposed that these contributions be treated as regulatory assets to be deferred until recovery is provided in the next base rate case of each company, at which time the regulatory assets will be amortized over the life of each project: four years with respect to the KCCS and ten years with respect to the CMRG. KU and LG&E jointly agreed to provide less than $2 million over two years to the KCCS and up to $2 million over ten years to the CMRG. In October 2008, an Order approving the establishment of the requested regulatory assets was received and rate recovery will be considered in each company's next base rate case.

TC2 CCN Application and Transmission Matters. A CCN application for construction of the new base-load, coal fired unit known as TC2, which will be jointly owned by KU and LG&E,

together with the Illinois Municipal Electric Agency and the Indiana Municipal Power Agency, was approved by the Kentucky Commission in November 2005.

Initial CCN applications for two transmission lines associated with the TC2 unit were approved by the Kentucky Commission in September 2005 and May 2006. One of those CCNs, for a line running from Jefferson County into Hardin County, was brought up for review to the Franklin Circuit Court by a group of landowners. In August 2006, KU, LG&E and the Kentucky Commission obtained dismissal of that action, on grounds that the landowners had failed to comply with the statutory procedures governing the action for review. That dismissal was appealed by the landowners to the Kentucky Court of Appeals, and in December 2007, that Court reversed the lower court's dismissal and remanded the challenge of the CCN to the Franklin Circuit Court for further proceedings. KU and LG&E filed a motion for discretionary review with the Kentucky Supreme Court in May 2008, asking that Court to hear the matter and, ultimately, to reverse the Court of Appeals and uphold the Franklin Circuit Court's dismissal, which motion has been opposed by the counter-parties.

The referenced transmission lines are also subject to routine regulatory filings and require the acquisition of easements. All rights of way for one transmission line have been acquired. In April 2008, in proceedings involving the condemnation of an easement for a portion of the Jefferson County to Hardin County transmission line, a Meade County, Kentucky court issued a ruling upholding the objections of two property co-owners and dismissed the condemnation proceeding pending the completion of the CCN appeal described above. KU and LG&E have filed responsive pleadings, including a motion to vacate that decision by the trial court and a procedural request with the Court of Appeals seeking expedited review on a petition to direct the circuit court to proceed with the condemnation litigation. Additional condemnation proceedings involving other parcels of property to support this transmission line are also pending in neighboring Hardin County where three landowners have challenged KU's and LG&E's right to easements, on the same grounds cited by the Meade County court and other purported bases, including asserted deficiencies in the air permit relating to the TC2 generation unit. In May, July and August 2008, the Hardin County Circuit Court issued rulings denying the property owners' various motions, finding that KU and LG&E had established their condemnation rights and granting judgment in favor of KU and LG&E. In August 2008, the property owners petitioned for intermediate relief to the Kentucky Court of Appeals and received a stay preventing KU and LG&E access to the properties. KU and LG&E have made responsive pleadings at the Court of Appeals and continue to engage in settlement negotiations with the property owners. In a separate, further proceeding, certain landowners have filed a lawsuit in federal court in Louisville, Kentucky against the U.S. Army, KU and LG&E alleging that the U.S. Army failed to comply with Section 106 of the National Historic Preservation Act in granting an easement across Fort Knox. KU and LG&E are working with the U.S. Army in defending against the claims. KU and LG&E are not currently able to predict the ultimate outcome and possible effects, if any, on the construction schedule relating to these real property proceedings.

Merger Surcredit. In December 2007, KU submitted its plan to allow the merger surcredit to terminate as scheduled on June 30, 2008, to the Kentucky Commission. In June 2008, the Kentucky Commission issued an Order approving a settlement which provides for continuation of the merger surcredit until new base rates go into effect.

VDT. In accordance with the Kentucky Commission's Order dated March 24, 2006, the VDT surcredit terminated in the first billing month after the filing for a change in base rates. As KU filed its application with the Kentucky Commission for an increase in base rates in July 2008, the VDT surcredit terminated with the first billing cycle in August 2008.

DSM. In July 2007, KU and LG&E filed an application with the Kentucky Commission requesting an order approving enhanced versions of the existing DSM programs along with the addition of several new cost effective programs. The total annual budget for these programs is approximately $26 million, an increase over the previous annual costs of approximately $10 million. In March 2008, the Kentucky Commission issued an Order approving the application, with minor modifications. KU and LG&E filed revised tariffs in April 2008, under authority of this Order, which were effective in May 2008.

Mandatory Reliability Standards. As a result of the EPAct 2005, certain formerly voluntary reliability standards became mandatory in June 2007, and authority was delegated to various RROs by the NERC, which was authorized by the FERC to enforce compliance with such standards, including promulgating new standards. Failure to comply with mandatory reliability standards can subject a registered entity to sanctions, including potential fines of up to $1 million per day, as well as non-monetary penalties, depending upon the circumstances of the violation. KU is a member of the SERC, which acts as KU's RRO. During May 2008, the SERC and KU agreed in principle to a settlement involving penalties totaling less than $1 million concerning KU's February 2008 self-report concerning possible violations of certain existing mitigation plans relating to reliability standards. The SERC and KU are currently involved in settlement negotiations concerning a June 2008 self-report by KU relating to three other standards. Additionally, KU has submitted to the SERC an October 2008 self report of a possible violation relating to one further standard, for which SERC proceedings are in the early stages and therefore unable to be determined. Mandatory reliability standard settlements commonly include other non-penalty elements, including compliance steps and mitigation plans. Settlements in principle with the SERC proceed to the NERC and FERC review before becoming final. While KU believes itself to be in compliance with the mandatory reliability standards, KU cannot predict the outcome of other analyses, including on-going SERC or other reviews described above.

Depreciation Study. In December 2007, KU filed a depreciation study with the Kentucky Commission as required by a previous Order. An adjustment to the depreciation rates is dependent on an order being received from the Kentucky Commission. In July 2008, KU filed a motion to consolidate the procedural schedule of the depreciation study with the application for a change in base rates. In August 2008, the Kentucky Commission issued an Order consolidating the depreciation study with the base rate case proceeding. KU also filed the depreciation study with the Virginia Commission, but has not requested formal review and approval of the depreciation rates from the Virginia Commission. Such a review will take place either during KU's next base rate case in Virginia or when KU makes a formal application to the Virginia Commission for approval of the proposed rates.

Brownfield Development Rider Tariff. In March 2008, KU received Kentucky Commission approval for a Brownfield Development Rider, which offers a discounted rate to electric customers who meet certain usage and location requirements, including taking new service at a brownfield site, as certified by the appropriate Kentucky state agency. The rider would permit special contracts with such customers which provide for a series of declining partial rate discounts over an initial five-year period of a longer service arrangement. The tariff is intended to promote local economic redevelopment and efficient usage of utility resources by aiding potential reuse of vacant brownfield sites.

Real-Time Pricing. In December 2006, the Kentucky Commission issued an Order indicating that the EPAct 2005 Section 1252, Smart Metering and Section 1254, Interconnection standards should not be adopted. However, five Kentucky Commission jurisdictional utilities were required to file real-time pricing pilot programs for their large commercial and industrial customers. KU developed a real-time pricing pilot for large industrial and commercial customers and filed the details of the plan with the Kentucky Commission in April 2007. In February 2008, the Kentucky Commission issued an Order approving the real-time pricing pilot program proposed by KU, for implementation within approximately eight months, for its large commercial and industrial customers. The tariff was filed in October 2008, with an effective date of December 1, 2008.

Utility Competition in Virginia. The Commonwealth of Virginia passed the Virginia Electric Utility Restructuring Act in 1999. This act gave Virginia customers the ability to choose their electric supplier. Rates are capped at current levels through December 2010. In April 2007, Virginia passed legislation terminating this competitive market and commencing re-regulation of utility rates in Virginia. The new act will end the cap on rates at the end of 2008, rather than through December 2010, and end customer choice for most consumers in the applicable regions of the state. Thereafter, a hybrid model of regulation is expected to apply in Virginia, whereby utility rates would be reviewed every two years and a utility's rate of return on equity shall not be set lower than the average of the rates of return for other regional utilities, with certain caps, floors or adjustments. The legislation was effective in July 2007, and also includes a 10% nonbinding goal for renewable power generation by 2022, as well as incentives for new generation, including renewables. Under the legislation, KU retains an existing exemption from customer choice and other restructuring activities as applicable to KU's limited service territory in Virginia. However, subject to future developments, KU may or may not undertake such a rate proceeding in the first six months of 2009 based on calendar year 2008 financial data under the hybrid model of regulation, or make biennial rate filings with the Virginia Commission thereafter.

Interconnection and Net Metering Guidelines. In May 2008, the Kentucky Commission on its own motion initiated a proceeding to establish interconnection and net metering guidelines in accordance with amendments to existing statutory requirements for net metering of electricity. The jurisdictional electric utilities and intervenors in this case presented the proposed interconnection guidelines to the Kentucky Commission in October 2008. An order is expected by the end of the year.

Note 3 - Financial Instruments

Energy Trading and Risk Management Activities (non-hedging derivatives). KU conducts energy trading and risk management activities to maximize the value of power sales from physical assets it owns. Energy trading activities are principally forward financial transactions to hedge price risk and are accounted for on a mark-to-market basis in accordance with SFAS No. 133, as amended.

No changes to valuation techniques for energy trading and risk management activities occurred during 2008 or 2007. Changes in market pricing, interest rate and volatility assumptions were made during both years. All contracts outstanding at September 30, 2008 and 2007, had a maturity of less than one year. Energy trading and risk management contracts are valued using Level 2, prices actively quoted for proposed or executed transactions or quoted by brokers or observable inputs other than quoted prices. Collateral related to the energy trading and risk management contracts is categorized as restricted cash.

Effective January 1, 2008, KU adopted the required provisions of SFAS No. 157, excluding the exceptions related to nonfinancial assets, which will be adopted effective January 1, 2009, consistent with FASB Staff Position 157-2. KU has classified the applicable financial assets that are accounted for at fair value into the three levels of the fair value hierarchy, as defined by SFAS No. 157. The following table sets forth by level within the fair value hierarchy KU's financial assets that were accounted for at fair value on a recurring basis as of September 30, 2008. Liabilities accounted for at fair value total less than $1 million and use Level 2 measurements. There are no Level 3 measurements for this period.

Recurring Fair Value Measurements (in millions)	Level 1	Level 2	Total
Assets:			
Energy trading and risk management contracts	$ -	$ 1	$ 1
Energy trading and risk management contracts cash collateral	1	-	1
Total Assets	$ 1	$ 1	$ 2

Note 4 - Pension and Other Postretirement Benefit Plans

The following tables provide the components of net periodic benefit cost for pension and other postretirement benefit plans. The tables include the costs associated with both KU employees and E.ON U.S. Services employees who are providing services to the utility. The E.ON U.S. Services costs that are allocated to KU are approximately 43% and 42% of E.ON U.S. Services total cost for 2008 and 2007, respectively.

Pension Benefits

(in millions)	Three Months Ended September 30, 2008	Three Months Ended September 30, 2007	Nine Months Ended September 30, 2008	Nine Months Ended September 30, 2007
Service cost	$ 3	$ 3	$ 9	$ 11
Interest cost	10	10	31	30
Expected return on plan assets	(12)	(12)	(35)	(37)
Amortization of prior service costs	1	1	1	1
Amortization of actuarial loss	-	1	1	3
Benefit cost	$ 2	$ 3	$ 7	$ 8

Other Postretirement Benefits

(in millions)	Three Months Ended September 30, 2008	Three Months Ended September 30, 2007	Nine Months Ended September 30, 2008	Nine Months Ended September 30, 2007
Service cost	$ 1	$ 1	$ 1	$ 1
Interest cost	1	2	4	4
Expected return on plan assets	-	-	(1)	(1)
Amortization of transition costs	-	-	1	1
Benefit cost	$ 2	$ 3	$ 5	$ 5

During 2008, KU made contributions to other postretirement benefits plans of $2 million. KU anticipates making further voluntary contributions to the postretirement plan, but no additional contributions to the pension plan in 2008.

Note 5 - Income Taxes

A United States consolidated income tax return is filed by E.ON U.S.'s direct parent, EUSIC, for each tax period. Each subsidiary of the consolidated tax group, including KU, calculates its separate income tax for each tax period. The resulting separate-return tax cost or benefit is paid to or received from the parent company or its designee. KU also files income tax returns in various state jurisdictions. With few exceptions, KU is no longer subject to U.S. federal income tax examinations for years before 2005. Statutes of limitations related to 2005 and later returns are still open. Tax years 2005, 2006 and 2007 are under audit by the IRS with the 2007 return being examined under an IRS pilot program named "Compliance Assurance Process". This program accelerates the IRS's review to begin during the year applicable to the return and ends 90 days after the return is filed.

KU adopted the provisions of FIN 48, *Accounting for Uncertainty in Income Taxes, an Interpretation of SFAS No. 109,* effective January 1, 2007. At the date of adoption, KU had less than $1 million of unrecognized tax benefits, primarily related to federal income taxes. If recognized, the amount of unrecognized tax benefits would reduce the effective income tax rate. Possible amounts of uncertain tax positions for KU that may decrease within the next 12 months total less than $1 million, and are based on the expiration of the audit periods as defined in the statutes.

The amount KU recognized as interest accrued related to unrecognized tax benefits was less than $1 million as of September 30, 2008 and December 31, 2007. The interest accrued is based on IRS and Kentucky Department of Revenue large corporate interest rates for underpayment of taxes. At the date of adoption, KU accrued less than $1 million in interest expense on uncertain tax positions. No penalties were accrued by KU upon adoption of FIN 48, or through September 30, 2008.

In June 2006, KU and LG&E filed a joint application with the U.S. Department of Energy ("DOE") requesting certification to be eligible for investment tax credits applicable to the construction of TC2. In November 2006, the DOE and the IRS announced that KU and LG&E were selected to receive the tax credit. A final IRS certification required to obtain the investment tax credit was received in August 2007. In September 2007, KU received an Order from the Kentucky Commission approving the accounting of the investment tax credit. KU's portion of the TC2 tax credit will be approximately $100 million over the construction period and will be amortized to income over the life of the related property beginning when the facility is placed in service. Based on eligible construction expenditures incurred, KU recorded investment tax credits of $9 million and $10 million during the three–month periods ended September 30, 2008 and 2007, respectively, and $22 million and $30 million during the nine months ended September 30, 2008 and 2007, respectively, decreasing current federal income taxes.

In March 2008, certain environmental and preservation groups filed suit in federal court in North Carolina against the DOE and IRS claiming the investment tax credit program was in violation of certain environmental laws and demanded relief, including suspension or termination of the program. In August 2008, the plaintiffs submitted an amended complaint alleging additional claims for relief. In November 2008, the Court dismissed the suit. The dismissal is subject to appeal by the plaintiffs; however, it is unclear at this time if they will do so. KU is not currently a party to this proceeding and is not able to predict the ultimate outcome of this matter.

Note 6 – Short-Term and Long-Term Debt

KU's long-term debt includes $33 million classified as current liabilities because these bonds are subject to tender for purchase at the option of the holder and to mandatory tender for purchase upon the occurrence of certain events. These bonds include Carroll County Series 2002 A and B, Muhlenberg County Series 2002 A and Mercer County Series 2002 A. These bonds mature in 2032. KU does not expect to pay these amounts in 2008. The average annualized interest rate for these bonds during the nine months ended September 30, 2008, was 1.90%.

As of September 30, 2008, KU maintained a bilateral line of credit totaling $35 million which matures in June 2012. At that time, there was no balance outstanding under this facility. See Note 9 Subsequent Events.

Pollution control series bonds are obligations of KU issued in connection with tax-exempt pollution control revenue bonds issued by various governmental entities, principally counties in Kentucky. A loan agreement obligates KU to make debt service payments to the county that equate to the debt service due from the county on the related pollution control revenue bonds. Until a series of financing transactions was completed during February 2007, the county's debt was also secured by an equal amount of KU's first mortgage bonds that were pledged to the trustee for the pollution control revenue bonds that match the terms and conditions of the county's debt, but require no payment of principal and interest unless KU defaults on the loan agreement. Subsequent to February 2007, the loan agreement is an unsecured obligation of KU. Proceeds from bond issuances for environmental equipment (primarily related to the installation of FGDs) were held in trust pending expenditure for qualifying assets. At September 30, 2008, KU had no bond proceeds in trust, and at December 31, 2007, KU had $11 million of bond proceeds in trust, included in restricted cash in the balance sheets.

Several of the KU pollution control bonds are insured by monoline bond insurers whose ratings have been under pressure due to exposures relating to insurance of sub-prime mortgages. At September 30, 2008, KU had an aggregate $333 million of outstanding pollution control indebtedness, of which $193 million is in the form of insured auction rate securities wherein interest rates are reset either weekly or every 35 days via an auction process. Beginning in late 2007, the interest rates on these insured bonds began to increase due to investor concerns about the creditworthiness of the bond insurers. In 2008, interest rates have continued to increase, and the Company has experienced "failed auctions" when there are insufficient bids for the bonds. When there is a failed auction, the interest rate is set pursuant to a formula stipulated in the indenture, which can be as high as 15%. During the nine months ended September 30, 2008 and 2007, the average rate on the auction rate bonds was 4.72% and 3.29%, respectively. The instruments governing these auction rate bonds permit KU to convert the bonds to other interest rate modes, such as various short-term variable rates, long-term fixed rates or intermediate-term fixed rates that are reset infrequently. In the first nine months of 2008, the ratings of the Carroll County 2004 Series A bonds were downgraded from Aaa to A2 by Moody's and from AAA to AA, and subsequently to A and then to BBB+, by S&P, and the Carroll County 2006 Series C bonds were downgraded from Aaa to A2 by Moody's and from AAA to A-, and subsequently to BBB+, by S&P due to downgrades of the bond insurer. The ratings of the following bonds were downgraded from Aaa to Aa3 by Moody's and from AAA to AA by S&P due to downgrades of the bond insurer: Mercer County 2000 Series A, Carroll County 2002 Series C, Carroll County 2005 Series A and B, Carroll County 2006 Series A and B, Carroll County 2007 Series A and Trimble County 2007 Series A.

In February 2008, KU issued a notice to bondholders of its intention to convert the Carroll County 2007 Series A bonds and the Trimble County 2007 Series A bonds from the auction rate mode to a fixed interest rate mode, as permitted under the loan documents. These conversions were completed in April 2008, and the new rates on the bonds are 5.75% and 6.00%, respectively.

In March 2008, KU issued notices to bondholders of its intention to convert the Carroll County 2006 Series C bonds and the Mercer County 2000 Series A bonds from the auction rate mode to a weekly interest rate mode, as permitted under the loan documents. The Carroll County conversion was completed in April 2008, and the Mercer County conversion was completed in May 2008. In connection with these conversions, KU purchased the bonds from the remarketing agent.

In June 2008, KU issued notices to bondholders of its intention to convert the Carroll County 2004 Series A bonds from the auction rate mode to a weekly interest rate mode, as permitted under the loan documents. The conversion was completed in July 2008. In connection with the conversion, KU purchased the bonds from the remarketing agent.

As of September 30, 2008, KU had repurchased bonds in the amount of $80 million. KU will hold some or all of such repurchased bonds until a later date, at which time KU may refinance, remarket or further convert such bonds. Uncertainty in markets relating to auction rate securities or steps KU has taken or may take to mitigate such uncertainty, such as additional conversion, subsequent restructurings or redemption and refinancing, could result in KU incurring increased interest expense, transaction expenses or other costs and fees or experiencing reduced liquidity relating to existing or future pollution control financing structures.

KU participates in an intercompany money pool agreement wherein E.ON U.S. and/or LG&E make funds available to KU at market-based rates (based on highly rated commercial paper issues) of up to $400 million. Details of the balances are as follows:

($ in millions)	Total Money Pool Available	Amount Outstanding	Balance Available	Average Interest Rate
September 30, 2008	$400	$116	$284	2.45%
December 31, 2007	$400	$ 23	$377	4.75%

E.ON U.S. maintains a revolving credit facility totaling $489 million at September 30, 2008 and $150 million at December 31, 2007, to ensure funding availability for the money pool. The revolving facility as of September 30, 2008, is split into separate loans totaling $489 million. One facility, totaling $150 million, is with E.ON North America, Inc., while the remaining loans, totaling $339 million, are with Fidelia; both are affiliated companies. The facility as of December 31, 2007, is with E.ON North America, Inc. The balances are as follows:

($ in millions)	Total Available	Amount Outstanding	Balance Available	Average Interest Rate
September 30, 2008	$489	$469	$20	3.94%
December 31, 2007	$150	$ 62	$88	4.97%

There were no redemptions of long-term debt year-to-date through September 30, 2008.

The issuances of long-term debt year-to-date through September 30, 2008, are summarized below:

($ in millions)

Year	Description	Principal Amount	Rate	Secured/ Unsecured	Maturity
2008	Due to Fidelia	$50	6.16%	Unsecured	2018
2008	Due to Fidelia	$50	5.645%	Unsecured	2018
2008	Due to Fidelia	$75	5.85%	Unsecured	2023

Note 7 - Commitments and Contingencies

Except as may be discussed in this quarterly report (including Note 2), material changes have not occurred in the current status of various commitments or contingent liabilities from that discussed in KU's Annual Report for the year ended December 31, 2007 (including in Notes 2 and 9 to the financial statements of KU contained therein). See the above-referenced notes in KU's Annual Report regarding such commitments or contingencies.

Owensboro Contract Litigation. In May 2004, the City of Owensboro, Kentucky and OMU commenced a suit now removed to the U.S. District Court for the Western District of Kentucky, against KU concerning a long-term power supply contract (the "OMU Agreement") with KU. The dispute involves interpretational differences regarding issues under the OMU Agreement, including various payments or charges between KU and OMU and rights concerning excess power, termination and emissions allowances. The complaint seeks in excess of $6 million in damages in connection with one of its claims for periods prior to 2004, plus damages in an unspecified amount for later-occurring periods on that claim and for other claims. OMU has additionally requested injunctive and other relief, including a declaration that KU is in material breach of the contract. KU has filed an answer in this proceeding denying the OMU claims and presenting counterclaims and amended such filing in January 2007, to include further counterclaims alleging additional damages.

During 2005, the FERC declined KU's application to exercise exclusive jurisdiction on matters. In July 2005, the district court resolved a summary judgment motion made by KU in OMU's favor, ruling that a contractual provision grants OMU the ability to terminate the contract without cause upon four years' prior notice. A motion to reconsider that ruling was later denied.

In May 2006, OMU issued a notification of its intent to terminate the OMU agreement contract in May 2010, without cause, absent any earlier relief which may be permitted by the proceeding, pursuant to the summary judgment in its favor. However, KU retains the right to appeal that summary judgment once the remaining claims in the lawsuit are adjudicated. The parties completed discovery and filed various dispositive motions before the court.

In September and October 2008, the court granted rulings on a number of summary judgment petitions in KU's favor, including determinations that KU's interpretation of facilities charge fund payments was accurate; that KU is the proportionate owner of NOx allowances allocated to the OMU plant by the government; that OMU's claim for back-up power charges should be capped at a certain price and a denial of OMU's petition to dismiss KU's counterclaim. The summary judgment rulings dismiss a substantial portion of OMU's material claims. Following the trial or other qualifying procedural occurrence, the various summary judgment motions would become appealable. The trial began on October 21, 2008 on the remaining matters before the court, including KU's counterclaim that OMU has failed to operate and maintain its plant in a good and workmanlike manner. The parties retain certain appeal rights and the Company is currently unable to determine the final outcome of this matter.

Construction Program. KU had approximately $224 million of commitments in connection with its construction program at September 30, 2008.

In June 2006, KU and LG&E entered into a construction contract regarding the TC2 project. The contract is generally in the form of a lump-sum, turnkey agreement for the design, engineering, procurement, construction, commissioning, testing and delivery of the project, according to designated specifications, terms and conditions. The contract price and its components are subject to a number of potential adjustments which may serve to increase or decrease the ultimate construction price paid or payable to the contractor. The contract also contains standard representations, covenants, indemnities, termination and other provisions for arrangements of this type, including termination for convenience or for cause rights.

TC2 Air Permit. The Sierra Club and other environmental groups filed a petition challenging the air permit issued for the TC2 baseload generating unit which was issued by the KDAQ in November 2005. The filing of the challenge did not stay the permit, so the Company was free to proceed with construction during the pendancy of the action. In June 2007, the state hearing officer assigned to the matter recommended upholding the air permit with minor revisions. In September 2007, the Secretary of the Kentucky Environmental and Public Protection Cabinet issued a final Order approving the hearing officer's recommendation and upholding the permit. In September 2007, KU administratively applied for a permit revision to reflect minor design changes. In October 2007, the environmental groups submitted comments objecting to the draft permit revisions and, in part, attempting to reassert general objections to the generating unit. In January 2008, the KDAQ issued a final permit revision. The environmental groups did not appeal the final Order upholding the permit or file a petition challenging the permit revision by the applicable deadlines. However, in October 2007, the environmental groups filed a lawsuit in federal court seeking an order for the EPA to grant or deny their pending petition for the EPA to "veto" the state air permit and in April 2008, they filed a petition seeking veto of the permit revision. In September 2008, the EPA issued an order denying nine of eleven claims alleged in one of the petitions, but finding deficiencies in two areas of the permit. The KDAQ has 90 days to respond to the EPA's order. Although the Company does not expect material changes in the permit as a result of the petitions, the EPA has yet to rule on several additional claims. The Company is currently unable to determine the final outcome of this matter or the impact of an unfavorable determination upon the Company's financial condition or results of operations.

Environmental Matters. KU's operations are subject to a number of environmental laws and regulations in each of the jurisdictions in which it operates, governing, among other things, air emissions, wastewater discharges, the use, handling and disposal of hazardous substances and wastes, soil and groundwater contamination and employee health and safety.

Clean Air Act Requirements. The Clean Air Act establishes a comprehensive set of programs aimed at protecting and improving air quality in the United States by, among other things, controlling stationary sources of air emissions such as power plants. While the general regulatory framework for these programs is established at the federal level, most of the programs are implemented and administered by the states under the oversight of the EPA. The key Clean Air Act programs relevant to KU's business operations are described below.

Ambient Air Quality. The Clean Air Act requires the EPA to periodically review the available scientific data for six criteria pollutants and establish concentration levels in the ambient air sufficient to protect the public health and welfare with an extra margin for safety. These concentration levels are known as NAAQS. Each state must identify "nonattainment areas" within its boundaries that fail to comply with the NAAQS and develop a SIP to bring such nonattainment areas into compliance. If a state fails to develop an adequate plan, the EPA must develop and implement a plan. As the EPA increases the stringency of the NAAQS through its periodic reviews, the attainment status of various areas may change, thereby triggering additional emission reduction obligations under revised SIPs aimed to achieve attainment.

In 1997, the EPA established new NAAQS for ozone and fine particulates that required additional reductions in SO_2 and NOx emissions from power plants. In 1998, the EPA issued its final "NOx SIP Call" rule requiring reductions in NOx emissions of approximately 85% from 1990 levels in order to mitigate ozone transport from the midwestern U.S. to the northeastern U.S. To implement the new federal requirements, Kentucky amended its SIP in 2002 to require electric generating units to reduce their NOx emissions to 0.15 pounds weight per MMBtu on a company-wide basis. In 2005, the EPA issued the CAIR which required additional SO_2 emission reductions of 70% and NOx emission reductions of 65% from 2003 levels. The CAIR provided for a two-phase cap and trade program, with initial reductions of NOx and SO_2 emissions due by 2009 and 2010, respectively, and final reductions due by 2015. In 2006, Kentucky proposed to amend its SIP to adopt state requirements similar to those under the federal CAIR. Depending on the level of action determined necessary to bring local nonattainment areas into compliance with the new ozone and fine particulate standards, KU's power plants are potentially subject to additional reductions in SO_2 and NOx emissions. In March 2008, the EPA issued a revised NAAQS for ozone, which contains a more stringent standard than that contained in the previous regulation. At present, KU is unable to determine what, if any, additional requirements may be imposed to achieve compliance with the new ozone standard.

In July 2008, a federal appeals court issued a ruling finding statutory and regulatory infirmities in the CAIR and potentially vacating it, and has conducted subsequent proceedings on the matter. During October 2008, the appellate court issued a ruling requesting briefs of the parties regarding whether vacating the CAIR is the applicable relief to be granted. KU, LG&E and industry parties are monitoring these further proceedings. Depending upon the course of such matters, the CAIR could be superseded by new or revised NOx or SO_2 regulations with different or more stringent requirements and SIPs which incorporate CAIR requirements could be subject to revision. KU is also reviewing aspects of its compliance plan relating to the CAIR, including scheduled or contracted pollution control construction programs. Finally, as discussed below, the current invalidation of the CAIR results in some uncertainty with respect to certain other EPA or state programs and proceedings and KU's and LG&E's compliance plans relating thereto, due to the interconnection of the CAIR and CAIR-associated steps with such associated programs. At present, KU is not able to predict the outcomes of the legal and regulatory proceedings related to the CAIR and whether such outcomes could have a material effect on the Company's financial or operational conditions.

Hazardous Air Pollutants. As provided in the 1990 amendments to the Clean Air Act, the EPA investigated hazardous air pollutant emissions from electric utilities and submitted a report to Congress identifying mercury emissions from coal-fired power plants as warranting further study. In 2005, the EPA issued the CAMR establishing mercury standards for new power plants and requiring all states to issue new SIPs including mercury requirements for existing power plants. The EPA issued a model rule which provides for a two-phase cap and trade program with initial reductions due by 2010 and final reductions due by 2018. The CAMR provided for reductions of 70% from 2003 levels. The EPA closely integrated the CAMR and CAIR programs to ensure that the 2010 mercury reduction targets would be achieved as a "co-benefit" of the controls installed for purposes of compliance with the CAIR.

In February 2008, a federal appellate court issued a decision vacating the CAMR. Certain parties have filed a petition seeking review in the U.S. Supreme Court. Depending on the final outcome of the pending appeal, the CAMR could be superseded by new mercury reduction rules with different or more stringent requirements. Kentucky has subsequently proposed to repeal the corresponding state mercury regulations. At present, KU is not able to predict the outcomes of the legal and regulatory proceedings related to the CAMR and whether such outcomes could have a material effect on the Companies' financial or operational conditions.

Acid Rain Program. The 1990 amendments to the Clean Air Act imposed a two-phased cap and trade program to reduce SO_2 emissions from power plants that were thought to contribute to "acid rain" conditions in the northeastern U.S. The 1990 amendments also contained requirements for power plants to reduce NOx emissions through the use of available combustion controls.

Regional Haze. The Clean Air Act also includes visibility goals for certain federally designated areas, including national parks, and requires states to submit SIPs that will demonstrate reasonable progress toward preventing future impairment and remedying any existing impairment of visibility in those areas. In 2005, the EPA issued its CAVR detailing how the Clean Air Act's BART requirements will be applied to facilities, including power plants, built between 1962 and 1974 that emit certain levels of visibility impairing pollutants. Under the final rule, as the CAIR provided for more visibility improvement than BART, states are allowed to substitute CAIR requirements in their regional haze SIPs in lieu of controls that would otherwise be required by BART. The final rule has been challenged in the courts. Additionally, because the regional haze SIPs incorporate certain CAIR requirements, the final outcome of the challenge to CAIR could potentially impact regional haze SIPs. See "Ambient Air Quality" above for a discussion of CAIR-related uncertainties.

Installation of Pollution Controls. Many of the programs under the Clean Air Act utilize cap and trade mechanisms that require a company to hold sufficient emissions allowances to cover its authorized emissions on a company-wide basis and do not require installation of pollution controls on every generating unit. Under cap and trade programs, companies are free to focus their pollution control efforts on plants where such controls are particularly efficient and utilize the resulting emission allowances for smaller plants where such controls are not cost effective. KU met its Phase I SO_2 requirements primarily through installation of FGD equipment on Ghent Unit 1. KU's strategy for its Phase II SO_2 requirements, which commenced in 2000, includes the installation of additional FGD equipment, as well as using accumulated emission allowances and fuel switching to defer certain additional capital expenditures. In order to achieve the NOx emission reductions and associated obligations, KU installed additional NOx controls, including SCR technology, during the 2000 to 2007 time period at a cost of $220 million. In 2001, the Kentucky Commission granted approval to recover the costs incurred by KU for these projects through the environmental surcharge mechanism. Such monthly recovery is subject to periodic review by the Kentucky Commission.

In order to achieve mandated emissions reductions, KU expects to incur additional capital expenditures totaling approximately $520 million during the 2008 through 2010 time period for pollution controls, including FGD and SCR equipment, and additional operating and maintenance costs in operating such controls. In 2005, the Kentucky Commission granted approval to recover the costs incurred by KU for these projects through the ECR mechanism. Such monthly recovery is subject to periodic review by the Kentucky Commission. KU believes its costs in reducing SO_2, NOx and mercury emissions to be comparable to those of similarly situated utilities with like generation assets. KU's compliance plans are subject to many factors including developments in the emission allowance and fuels markets, future legislative and regulatory enactments, legal proceedings and advances in clean air technology. KU will continue to monitor these developments to ensure that its environmental obligations are met in the most efficient and cost-effective manner. See "Ambient Air Quality" above for a discussion of CAIR-related uncertainties.

Potential GHG Controls. In 2005, the Kyoto Protocol for reducing GHG emissions took effect, obligating 37 industrialized countries to undertake substantial reductions in GHG emissions. The U.S. has not ratified the Kyoto Protocol and there are currently no mandatory GHG emission reduction requirements at the federal level. Legislation mandating GHG reductions has been introduced in the Congress, but no federal legislation has been enacted to date. In the absence of a program at the federal level, various states have adopted their own GHG emission reduction programs. Such programs have been adopted in various states including 11 northeastern U.S. states and the District of Columbia under the Regional GHG Initiative program and California. Substantial efforts to pass federal GHG legislation are ongoing. In April 2007, the U.S. Supreme Court ruled that the EPA has the authority to regulate GHG under the Clean Air Act. KU is monitoring ongoing efforts to enact GHG reduction requirements at the state and federal level and is assessing potential impacts of such programs and strategies to mitigate those impacts. KU is also monitoring relevant regulatory proceedings involving the EPA's advanced notice of proposed rulemaking for regulation of GHGs under the existing authority of the Clean Air Act and proposed rules governing carbon sequestration. KU is unable to predict whether mandatory GHG reduction requirements will ultimately be enacted. As a Company with significant coal-fired generating assets, KU could be substantially impacted by programs requiring mandatory reductions in GHG emissions, although the precise impact on the operations of KU, including the reduction targets and deadlines that would be applicable, cannot be determined prior to the enactment of such programs.

Brown New Source Review Litigation. In April 2006, the EPA issued an NOV alleging that KU had violated certain provisions of the Clean Air Act's new source review rules relating to work performed in 1997, on a boiler and turbine at KU's E.W. Brown generating station. In December 2006, the EPA issued a second NOV alleging the Company had exceeded heat input values in violation of the air permit for the unit. In March 2007, the U.S. Department of Justice filed a complaint in federal court in Kentucky alleging the same violations specified in the prior NOVs. The complaint seeks civil penalties, including potential per-day fines, remedial measures and injunctive relief. In April 2007, KU filed an answer in the civil suit denying the allegations. In July 2007, the court entered a schedule providing for a July 2009 date for trial. The parties are currently proceeding with discovery while concurrently engaged in active settlement negotiations. A $3 million accrual has been recorded based on the current status of those discussions, however, KU cannot determine the overall outcome or potential effects of these matters, including whether substantial fines, penalties or remedial measures may result, which could be in excess of the amount reserved. Also of uncertain potential effect, if any, is the invalidation of the CAIR on the progress or content of settlement discussions. See "Ambient Air Quality" above for a discussion of CAIR-related uncertainties.

Section 114 Requests. In August 2007, the EPA issued administrative information requests under Section 114 of the Clean Air Act requesting new source review-related data regarding certain projects undertaken at LG&E's Mill Creek 4 and Trimble County 1 generating units and KU's

Ghent 2 generating unit. KU and LG&E have complied with the information requests and are not able to predict further proceedings in this matter at this time.

Ghent Opacity NOV. In September 2007, the EPA issued an NOV alleging that KU had violated certain provisions of the Clean Air Act's operating rules relating to opacity during June and July of 2007 at Units 1 and 3 of KU's Ghent generating station. The parties have met on this matter and KU has received no further communications from the EPA. KU is not able to estimate the outcome or potential effects of these matters, including whether substantial fines, penalties or remedial measures may result.

General Environmental Proceedings. From time to time, KU appears before the EPA, various state or local regulatory agencies and state and federal courts regarding matters involving compliance with applicable environmental laws and regulations. Such matters include liability under the Comprehensive Environmental Response, Compensation and Liability Act for cleanup at various off-site waste sites and claims regarding GHG emissions from KU's generating stations. Based on analysis to date, the resolution of these matters is not expected to have a material impact on the operations of KU.

Note 8 - Related Party Transactions

KU, subsidiaries of E.ON U.S. and subsidiaries of E.ON engage in related party transactions. Transactions between KU and E.ON U.S. subsidiaries are eliminated upon consolidation of E.ON U.S. Transactions between KU and E.ON subsidiaries are eliminated upon consolidation of E.ON. These transactions are generally performed at cost and are in accordance with the FERC regulations under PUHCA 2005 and the applicable Kentucky Commission and Virginia Commission regulations. The significant related party transactions are disclosed below.

Electric Purchases

KU and LG&E purchase energy from each other in order to effectively manage the load of their retail and wholesale customers. These sales and purchases are included in the statements of income as operating revenues and purchased power operating expense. KU intercompany electric revenues and purchased power expense were as follows:

	Three Months Ended September 30,		Nine Months Ended September 30,	
(in millions)	2008	2007	2008	2007
Electric operating revenues from LG&E	$15	$ 7	$44	$33
Purchased power from LG&E	21	18	73	71

Interest Charges

See Note 6, Short-Term and Long-Term Debt, for details of intercompany borrowing arrangements. Intercompany agreements do not require interest payments for receivables related to services provided when settled within 30 days.

KU's intercompany interest expense was as follows:

(in millions)	Three Months Ended September 30, 2008	Three Months Ended September 30, 2007	Nine Months Ended September 30, 2008	Nine Months Ended September 30, 2007
Interest on money pool loans	$ 1	$ 2	$ 1	$ 5
Interest on Fidelia loans	14	9	40	24

Other Intercompany Billings

E.ON U.S. Services provides KU with a variety of centralized administrative, management and support services. These charges include payroll taxes paid by E.ON U.S. on behalf of KU, labor and burdens of E.ON U.S. Services employees performing services for KU, coal purchases and other vouchers paid by E.ON U.S. Services on behalf of KU. The cost of these services is directly charged to KU, or for general costs which cannot be directly attributed, charged based on predetermined allocation factors, including the following ratios: number of customers, total assets, revenues, number of employees and other statistical information. These costs are charged on an actual cost basis.

In addition, KU and LG&E provide services to each other and to E.ON U.S. Services. Billings between KU and LG&E relate to labor and overheads associated with union employees performing work for the other utility, charges related to jointly-owned generating units and other miscellaneous charges. Billings from KU to E.ON U.S. Services relate to cash received by E.ON U.S. Services on behalf of KU, primarily tax settlements, and other payments made by KU on behalf of other non-regulated businesses which are reimbursed through E.ON U.S. Services.

Intercompany billings to and from KU were as follows:

(in millions)	Three Months Ended September 30, 2008	Three Months Ended September 30, 2007	Nine Months Ended September 30, 2008	Nine Months Ended September 30, 2007
E.ON U.S. Services billings to KU	$62	$42	$173	$389
KU billings to LG&E	21	11	58	33
LG&E billings to KU	-	2	5	35
KU billings to E.ON U.S. Services	-	22	2	24

In June 2008, LG&E transferred assets related to Trimble County Unit 2 with a net book value of $10 million to KU.

In March, June and September 2008, KU received capital contributions from its common shareholder, E.ON U.S., in the amounts of $25 million, $50 million and $50 million, respectively.

Note 9 – Subsequent Events

On October 17, 2008, KU closed on a new $78 million bilateral line of credit which has a 364 day maturity.

On October 17, 2008, KU issued Carroll County 2008 Series A tax exempt bonds in the amount of $78 million. The new bonds mature on February 1, 2032, and bear interest at a variable rate. The new bonds refinance four existing Series F bonds (Carroll County 2005 Series A and C - $13 million each and the Carroll County 2006 Series A and C - $17 million each), and includes $18 million of new funding. The proceeds from the new funding will be held in escrow pending incurrence of qualifying expenditures.

On October 27, 2008, KU filed an application with the Kentucky Commission requesting approval to establish a regulatory asset, and defer for future recovery, $3 million of expenses related to the Hurricane Ike wind storm restoration. An order has been requested by the end of the year.

On October 30, 2008, the Kentucky Commission issued an Order approving the establishment of regulatory assets for the Companies' contributions to the CMRG and KCCS. Rate recovery will be considered in each company's next base rate case.

On November 5, 2008, the ratings of the Mercer County 2000 Series A bonds, Carroll County 2002 Series C bonds, Carroll County 2006 Series B bonds, Carroll County 2007 Series A bonds and Trimble County 2007 Series A bonds were downgraded from Aa3 to A2 by Moody's, due to downgrades of the bond insurer.

Management's Discussion and Analysis of Financial Condition and Results of Operations

General

The following discussion and analysis by management focuses on those factors that had a material effect on KU's financial results of operations and financial condition during the three and nine month periods ended September 30, 2008, and should be read in connection with the financial statements and notes thereto.

Some of the following discussion may contain forward-looking statements that are subject to certain risks, uncertainties and assumptions. Such forward-looking statements are intended to be identified in this document by the words "anticipate," "expect," "estimate," "objective," "possible," "potential" and similar expressions. Actual results may vary materially. Factors that could cause actual results to differ materially include: general economic conditions; business and competitive conditions in the energy industry; changes in federal or state legislation; unusual weather; actions by state or federal regulatory agencies; and other factors described from time to time in the Company's reports, including the Annual Report for the year ended December 31, 2007.

Executive Summary

Business

KU, incorporated in Kentucky in 1912 and in Virginia in 1991, is a regulated public utility engaged in the generation, transmission, distribution and sale of electric energy in Kentucky, Virginia and Tennessee. As of September 30, 2008, KU provided electricity to approximately 507,000 customers in 77 counties in central, southeastern and western Kentucky, approximately 30,000 customers in 5 counties in southwestern Virginia and 5 customers in Tennessee. KU's service area covers approximately 6,600 square miles. KU's coal-fired electric generating stations produce most of KU's electricity. The remainder is generated by a hydroelectric power plant and natural gas and oil fueled combustion turbines. In Virginia, KU operates under the name Old Dominion Power Company. KU also sells wholesale electric energy to 12 municipalities.

KU is a wholly-owned subsidiary of E.ON U.S., an indirect wholly-owned subsidiary of E.ON, a German corporation, making KU an indirect wholly-owned subsidiary of E.ON. KU's affiliate, LG&E, is a regulated public utility engaged in the generation, transmission, distribution and sale of electric energy and the distribution of natural gas in Kentucky.

In July 2008, KU filed an application with the Kentucky Commission requesting increases in base electric rates of approximately 2.0% or $22 million annually. In conjunction with the filing of the application for a change in base rates, based on previous Orders by the Kentucky Commission approving settlement agreements among all interested parties, the VDT surcredit terminated in August 2008, and the merger surcredit will terminate upon the implementation of new base rates. The termination of the VDT surcredit and merger surcredit will result in a $16 million increase in revenues annually. A hearing for the Kentucky base rate case is scheduled beginning on January 13, 2009. The requested rates have been suspended until February 5, 2009, at which time they may be put into effect, subject to refund, if the Kentucky Commission has not issued an order in the proceeding.

In September 2008, high winds from the remnants of the Hurricane Ike wind storm passed through KU's service territory causing significant outages and system damage. In October 2008, KU filed an application with the Kentucky Commission requesting approval to establish a regulatory asset, and defer for future recovery, $3 million of expenses related to the storm restoration. An order has been requested by the end of the year.

Environmental Matters

Protection of the environment is a major priority for KU. Federal, state and local regulatory agencies have issued KU permits for various activities subject to air quality, water quality and waste management laws and regulations. See Note 7 of Notes to Financial Statements for more information.

Results of Operations

The electric utility business is affected by seasonal temperatures. As a result, operating revenues (and associated operating expenses) are not generated evenly throughout the year.

Three Months Ended September 30, 2008, Compared to Three Months Ended September 30, 2007

Net Income

Net income for the three months ended September 30, 2008, decreased $7 million compared to the same period in 2007. The decrease was primarily the result of increased operating expense ($34 million), increased interest expense ($4 million) and increased income taxes ($1 million), partially offset by increased electric revenues ($26 million) and other income ($6 million).

Revenues

Revenues increased $26 million in the three months ended September 30, 2008, primarily due to:

- Increased fuel costs billed to customers through the FAC ($23 million) due to increased fuel prices
- Increased wholesale sales ($12 million) due to increased intercompany volumes, increased wholesale market pricing and increased volume due to decreased native load
- Increased ECR surcharge ($8 million) due to increased recoverable capital spending
- Increased demand charges ($5 million) due to higher peak load
- Decreased sales volumes to native load ($24 million) due in part to a 19% decrease in cooling degree days and outages related to damage from the Hurricane Ike wind storm

Expenses

Fuel for electric generation comprises a large component of total operating expenses. Increases or decreases in the cost of fuel are reflected in retail rates through the FAC, subject to the approval of the Kentucky Commission, the Virginia Commission and the FERC.

Fuel for electric generation increased $9 million in the three months ended September 30, 2008, primarily due to:

- Increased commodity and transportation costs for coal and natural gas ($14 million)
- Decreased generation ($5 million) due to decreased native load

Power purchased expense increased $15 million in the three months ended September 30, 2008, primarily due to:

- Increased pricing and volumes on purchases for native load ($9 million) due to increased coal and gas costs and unit outages
- Increased intercompany volumes purchased ($4 million) due to lower native load requirements for LG&E as a result of milder weather, lower industrial sales and power outages from the Hurricane Ike wind storm, resulting in the purchase of excess power from LG&E
- Increased demand payments ($1 million) due to a new capacity contract

Other operation and maintenance expense increased $5 million in the three months ended September 30, 2008, due to increased maintenance expense ($3 million) and increased other operation expense ($2 million).

Maintenance expense increased $3 million in the three months ended September 30, 2008, primarily due to:

- Increased electric maintenance ($1 million) due to higher cost of outside contractors and materials
- Increased distribution maintenance ($1 million) due to the Hurricane Ike wind storm
- Increased cost for other indirect maintenance ($1 million) due to increased software maintenance lease cost

Other operation expense increased $2 million in the three months ended September 30, 2008, primarily due to increased outside services due to increased legal expenses as a result of ongoing litigation, mainly with OMU.

Interest expense, including interest expense to affiliated companies, increased $4 million in the three months ended September 30, 2008, primarily due to increased interest expense to affiliated companies due to increased borrowing.

	Three Months Ended September 30, 2008	Three Months Ended September 30, 2007
Effective Rate		
Statutory federal income tax rate	35.0%	35.0%
State income taxes net of federal benefit	2.8	3.1
Reduction of income tax reserve	(0.8)	(0.7)
Amortization of investment tax credits	(0.2)	(0.1)
Dividends received deduction related to EEI Investment	(3.9)	(2.5)
Other differences	(2.3)	(8.3)
Effective income tax rate	30.6%	26.5%

The effective income tax rate increased for the three months ended September 30, 2008, compared to the three months ended September 30, 2007 due primarily to the tax benefits resulting from income tax estimates recorded in 2006 being adjusted to the actual income tax return filed, which is included in the other differences, in the three months ended September 30, 2007. This was partially offset by decreased state income taxes net of federal benefit due to an increase in state coal credits and an increase in tax benefits associated with increased dividends received from EEI.

Nine Months Ended September 30, 2008 Compared to
Nine Months Ended September 30, 2007

Net Income

Net income for the nine months ended September 30, 2008, decreased $13 million compared to the same period in 2007. The decrease was primarily the result of increased operating expense ($95 million) and increased interest expense ($11 million), partially offset by increased electric revenues ($76 million), lower income taxes ($9 million) and higher other income ($8 million).

Revenues

Revenues in the nine months ended September 30, 2008, increased $76 million primarily due to:

- Increased fuel costs billed to customers through the FAC ($85 million) due to increased fuel prices
- Increased wholesale sales ($19 million) due to increased wholesale market pricing and increased volume due to decreased native load
- Decreased sales volumes delivered to native load ($28 million) due in part to a 24% decrease in cooling degree days

Expenses

Fuel for electric generation comprises a large component of total operating expenses. Increases or decreases in the cost of fuel are reflected in retail rates through the FAC, subject to the approval of the Kentucky Commission, the Virginia Commission and the FERC.

Fuel for electric generation increased $26 million in the nine months ended September 30, 2008, primarily due to:

- Increased commodity and transportation costs for coal and natural gas ($21 million)
- Increased generation ($5 million) due to increased wholesale sales

Power purchased expense increased $35 million in the nine months ended September 30, 2008, primarily due to:

- Increased pricing and volumes on purchases for native load ($28 million) due to increased coal and gas costs and unit outages
- Increased intercompany costs ($4 million) due to higher fuel costs
- Increased demand payments ($2 million) due to a capacity contract
- Increased wholesale purchase cost ($1 million) due to increased volumes and prices

Other operation and maintenance expense increased $24 million in the nine months ended September 30, 2008, due to increased maintenance expense ($13 million) and increased other operation expense ($11 million).

Maintenance expense increased $13 million in the nine months ended September 30, 2008, primarily due to:

- Increased electric and boiler maintenance expense ($5 million) due to higher cost of outside contractors and materials
- Increased overhead conductor and devices maintenance expense ($4 million) due to the Hurricane Ike wind storm and other storm restoration earlier in the year
- Increased steam maintenance expense ($2 million) due to high energy piping inspections and repairs
- Increased cost for other indirect maintenance ($2 million) due to increased software maintenance lease cost

Other operation expense increased $11 million in the nine months ended September 30, 2008, primarily due to:

- Increased generation expense due to increased unit outages and increased transmission expense to cover native load demand ($4 million)
- Increased outside services ($3 million) due to increased legal expenses as a result of ongoing litigation, mainly with OMU
- Increased expense for uncollectible accounts ($2 million)
- Increased cost of consumables ($1 million) primarily due to increased contract pricing
- Increased distribution expense ($1 million) due to the Hurricane Ike wind storm and other storm restoration earlier in the year

Interest expense, including interest expense to affiliated companies, increased $11 million in the nine months ended September 30, 2008, primarily due to increased interest expense to affiliated companies due to increased borrowing.

	Nine Months Ended September 30, 2008	Nine Months Ended September 30, 2007
Effective Rate		
Statutory federal income tax rate	35.0%	35.0%
State income taxes net of federal benefit	2.8	3.3
Reduction of income tax reserve	(0.3)	(0.3)
Amortization of investment tax credits	(0.1)	(0.2)
Dividends received deduction related to EEI investment	(4.3)	(2.7)
Other differences	(2.7)	(3.5)
Effective income tax rate	30.4%	31.6%

The effective income tax rate decreased for the nine months ended September 30, 2008, compared to the nine months ended September 30, 2007. State income taxes net of federal benefit decreased due to an increase in state coal credits. Also contributing to the lower effective rate were the tax benefits associated with increased dividends received from EEI.

Liquidity and Capital Resources

KU uses net cash generated from its operations, external financing (including financing from affiliates) and/or infusions of capital from its parent mainly to fund construction of plant and equipment. KU currently has a working capital deficiency of $97 million, primarily due to short-term debt from affiliates associated with the repurchase of certain of its tax-exempt bonds totaling $80 million. These bonds are being held until they can be refinanced or restructured. See Notes 6 and 9 of Notes to Financial Statements. KU believes that its sources of funds will be sufficient to meet the needs of its business in the foreseeable future.

KU and LG&E sponsor pension and postretirement benefit plans for their employees. The performance of the capital markets affects the values of the assets that are held in trust to satisfy future obligations under the defined benefit pension plans. The market value of the combined investments within the plans declined by approximately 18% during the nine months ended September 30, 2008 due to the recent volatility in the capital markets. The benefit plan assets and obligations of KU and LG&E are remeasured annually using a December 31 measurement date. KU and LG&E expect that investment losses will result in an increase to the plans' unfunded status upon actuarial revaluation of the plans. Changes in the value of plan assets will not impact the income statement for 2008; however, reduced benefit plan assets will result in increased benefit costs in future years and may increase the amount, and accelerate the timing of, required future funding contributions. Such increases could be material to KU and LG&E beginning in 2009, however, the amount of such contributions cannot be determined at this time.

Operating Activities

Cash provided by operations was $243 million and $209 million for the nine months ended September 30, 2008 and 2007, respectively.

The 2008 increase of $34 million was primarily the result of increases in cash due to changes in:

- Accounts payable ($37 million)
- FAC receivable, net ($26 million)
- Pension funding ($11 million) due to higher pension funding in 2007
- Other current liabilities ($7 million)
- Accounts receivable ($5 million)
- Other ($1 million)

These increases were partially offset by cash provided by changes in:

- Materials and supplies ($34 million)
- Earnings, net of non-cash items ($10 million)
- Prepayments and other current assets ($9 million)

Investing Activities

The primary use of funds for investing activities continues to be for capital expenditures. Capital expenditures were $554 million and $512 million in the nine months ended September 30, 2008 and 2007, respectively. Net cash used for investing activities increased $25 million in the nine months ended September 30, 2008, compared to 2007, primarily due to increased capital expenditures of $42 million and an asset transferred from LG&E of $10 million. The increase in restricted cash of $27 million represents the escrowed proceeds of the pollution control bonds issued, which were disbursed as qualifying costs were incurred.

Financing Activities

Net cash inflows from financing activities were $313 million and $315 million in the nine months ended September 30, 2008 and 2007, respectively. Net cash provided by financing activities decreased $2 million in the nine months ended September 30, 2008 compared to 2007, due to decreased long-term borrowings from an affiliated company of $103 million, the issuance of pollution control bonds of $81 million in 2007 and the reacquisition of bonds in the amount of $80 million, partially offset by the retirement of first mortgage bonds of $107 million in 2007, increased short-term borrowings from an affiliated company of $85 million and increased infusions from E.ON U.S. of $70 million.

See Note 6 of Notes to Financial Statements for information of redemptions, maturities and issuances of long-term debt.

Future Capital Requirements

KU's construction program is designed to ensure that there will be adequate capacity and reliability to meet the electric needs of its service area and to comply with environmental regulations. These needs are continually being reassessed and appropriate revisions are made, when necessary, in construction schedules. KU expects its capital expenditures for the three year period ending December 31, 2010, to total approximately $1,465 million, consisting primarily of construction estimates for installation of FGDs on Ghent and Brown units totaling approximately $425 million, construction of TC2 totaling approximately $360 million, the Brown ash pond totaling approximately $40 million, a customer care system totaling approximately $25 million, on-going construction related to generation assets totaling approximately $360 million and distribution assets totaling approximately $230 million and other projects including information technology of approximately $25 million.

Future capital requirements may be affected in varying degrees by factors such as electric energy demand load growth, changes in construction expenditure levels, rate actions by regulatory agencies, new legislation, changes in commodity prices and labor rates, changes in environmental regulations and other regulatory requirements. KU anticipates funding future capital requirements through operating cash flow, debt and/or infusions of capital from its parent.

KU has a variety of funding alternatives available to meet its capital requirements. KU participates in an intercompany money pool agreement wherein E.ON U.S. and/or LG&E make funds of up to $400 million available to KU at market-based rates. Fidelia also provides long-term intercompany funding to KU. See Note 6 of Notes to Financial Statements.

Regulatory approvals are required for KU to incur additional debt. The Virginia Commission and the FERC authorize the issuance of short-term debt while the Kentucky Commission, the Virginia Commission and the Tennessee Regulatory Authority authorize the issuance of long-term debt. In November 2007, KU received a two-year authorization from the FERC to borrow up to $400 million in short-term funds. KU also has authorization from the Virginia Commission that expires at the end of 2009 allowing short-term borrowing of up to $400 million.

KU's debt ratings as of September 30, 2008, were:

	Moody's	S&P
Issuer rating	A2	-
Corporate credit rating	-	BBB+

These ratings reflect the views of Moody's and S&P. A security rating is not a recommendation to buy, sell or hold securities and is subject to revision or withdrawal at any time by the rating agency. See Note 6 of Notes to Financial Statements for a discussion of recent downgrade actions related to the pollution control revenue bonds caused by a change in the rating of the entity insuring those bonds.

Controls and Procedures

The Company is responsible for establishing and maintaining adequate internal control over financial reporting. Internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

The Company has assessed the effectiveness of its internal control over financial reporting as of December 31, 2007. In making this assessment, the Company used the criteria set forth by the Committee of Sponsoring Organizations of the Treadway Commission in Internal Control - Integrated Framework . The Company has concluded that, as of December 31, 2007, the Company's internal control over financial reporting was effective based on those criteria. There has been no change in the Company's internal control over financial reporting that occurred during the nine months ended September 30, 2008, that has materially affected, or is reasonably likely to materially affect, the Company's internal control over financial reporting.

KU is not subject to the internal control and other requirements of the Sarbanes-Oxley Act of 2002 and associated rules (the "Act") and consequently is not required to evaluate the effectiveness of the Company's internal control over financial reporting pursuant to Section 404 of the Act. However, as discussed above, management has evaluated the effectiveness of internal control over financial reporting as of December 31, 2007. Management's assessment was not subject to audit by the Company's independent accounting firm.

Legal Proceedings

For a description of the significant legal proceedings involving KU, reference is made to the information under the following captions of KU's Financial Statements and Additional Information for the year ended December 31, 2007 (the "Annual Report"): Business, Risk Factors, Legal Proceedings, Management's Discussion and Analysis, Financial Statements and Notes to Financial Statements. Reference is also made to the matters described in Notes 2 and 7 of this quarterly report. Except as described in this quarterly report, to date, the proceedings reported in KU's Annual Report have not materially changed.

Other

In the normal course of business, other lawsuits, claims, environmental actions and other governmental proceedings arise against KU. To the extent that damages are assessed in any of these lawsuits, KU believes that its insurance coverage is adequate. Management, after consultation with legal counsel, does not anticipate that liabilities arising out of other currently pending or threatened lawsuits and claims will have a material adverse effect on KU's financial position or results of operations.

Kentucky Utilities Company

Financial Statements and Additional Information

As of December 31, 2007 and 2006

TABLE OF CONTENTS

INDEX OF ABBREVIATIONS

AG	Attorney General of Kentucky
ARO	Asset Retirement Obligation
BART	Best Available Retrofit Technology
CAIR	Clean Air Interstate Rule
CAMR	Clean Air Mercury Rule
CCN	Certificate of Public Convenience and Necessity
Clean Air Act	The Clean Air Act, as amended in 1990
Company	KU
CT	Combustion Turbines
DSM	Demand Side Management
ECR	Environmental Cost Recovery
EEI	Electric Energy, Inc.
E.ON	E.ON AG
E.ON U.S.	E.ON U.S. LLC (formerly LG&E Energy LLC and LG&E Energy Corp.)
E.ON U.S. Services	E.ON U.S. Services Inc. (formerly LG&E Energy Services Inc.)
EPA	U.S. Environmental Protection Agency
EPAct 2005	Energy Policy Act of 2005
FAC	Fuel Adjustment Clause
FASB	Financial Accounting Standards Board
FERC	Federal Energy Regulatory Commission
FGD	Flue Gas Desulfurization
Fidelia	Fidelia Corporation (an E.ON affiliate)
FIN	FASB Interpretation No.
GHG	Greenhouse Gas
IBEW	International Brotherhood of Electrical Workers
IRP	Integrated Resource Plan
IRS	Internal Revenue Service
Kentucky Commission	Kentucky Public Service Commission
KIUC	Kentucky Industrial Utility Consumers, Inc.
KU	Kentucky Utilities Company
Kwh	Kilowatt hours
LG&E	Louisville Gas and Electric Company
LG&E Energy	LG&E Energy LLC (now E.ON U.S. LLC)
MISO	Midwest Independent Transmission System Operator, Inc.
MMBtu	Million British thermal units
Moody's	Moody's Investor Services, Inc.
MVA	Megavolt-ampere
Mw	Megawatts
Mwh	Megawatt hours
NOV	Notice of Violation
NOx	Nitrogen Oxide
OMU	Owensboro Municipal Utilities
OVEC	Ohio Valley Electric Corporation
PUHCA 2005	Public Utility Holding Company Act of 2005
S&P	Standard & Poor's Rating Services
SCR	Selective Catalytic Reduction
SFAS	Statement of Financial Accounting Standards
SIP	State Implementation Plan
SO_2	Sulfur Dioxide
TC2	Trimble County Unit 2
VDT	Value Delivery Team Process
Virginia Commission	Virginia State Corporation Commission

Business

GENERAL

KU, incorporated in Kentucky in 1912 and in Virginia in 1991, is a regulated public utility engaged in the generation, transmission, distribution and sale of electric energy in Kentucky, Virginia and Tennessee. KU provides electricity to approximately 506,000 customers in 77 counties in central, southeastern and western Kentucky, to approximately 30,000 customers in 5 counties in southwestern Virginia and 5 customers in Tennessee. KU's service area covers approximately 6,600 square miles. KU's coal-fired electric generating stations produce most of KU's electricity. The remainder is generated by a hydroelectric power plant and natural gas and oil fueled CTs. In Virginia, KU operates under the name Old Dominion Power Company. KU also sells wholesale electric energy to 12 municipalities.

KU is a wholly-owned subsidiary of E.ON U.S., formerly known as LG&E Energy LLC. E.ON U.S. is an indirect wholly-owned subsidiary of E.ON, a German corporation, making KU an indirect wholly-owned subsidiary of E.ON. KU's affiliate, LG&E, is a regulated public utility engaged in the generation, transmission, distribution and sale of electric energy and the distribution and sale of natural gas in Kentucky.

OPERATIONS

The sources of operating revenues and volumes of sales for the years ended December 31, 2007 and 2006, were as follows:

	2007		2006	
	Revenues (millions)	Volumes (000Mwh)	Revenues (millions)	Volumes (000Mwh)
Residential	$ 430	6,847	$ 380	6,313
Industrial & Commercial	597	11,047	547	10,776
Municipals	90	2,058	85	1,978
Other Retail	98	1,691	89	1,608
Wholesale	58	1,582	109	2,473
Total	$1,273	23,225	$1,210	23,148

KU set a new record peak load of 4,344 Mw on August 9, 2007, when the temperature reached 98 degrees Fahrenheit in Lexington.

KU's power generating system includes coal-fired units operated at its four steam generating stations. Natural gas and oil fueled CTs supplement the system during peak or emergency periods. As of December 31, 2007, KU owned and operated the following generating stations while maintaining a 12%-14% reserve margin:

	Summer Capability Rating (Mw)
Steam Stations:	
Tyrone – Woodford County, KY	71
Green River – Muhlenberg County, KY	163
E.W. Brown – Mercer County, KY	697
Ghent – Carroll County, KY	1,932
Total Steam Stations	2,863
Dix Dam Hydroelectric Station – Mercer County, KY	24
CT Generators (Peaking capability):	
E.W. Brown – Mercer County, KY*	757
Haefling – Fayette County, KY	36
Paddy's Run – Jefferson County, KY *	74
Trimble County – Trimble County, KY *	632
Total CT Generators	1,499
Total Capability Rating	4,386

* Some of these units are jointly owned with LG&E. See Note 10 of Notes to Financial Statements for information regarding jointly owned units.

At December 31, 2007, KU's transmission system included 111 substations (39 of which are shared with the distribution system) with a total capacity of approximately 17,223 MVA and approximately 4,030 miles of lines. The distribution system included 481 substations (39 of which are shared with the transmission system) with a total capacity of approximately 6,653 MVA, 14,082 miles of overhead lines and 2,046 miles of underground conduit.

KU has a purchase power agreement with OMU, owns 20% of EEI's common stock and owns 2.5% of OVEC's common stock. Additional information regarding these relationships is provided in Notes 1 and 9 of Notes to Financial Statements.

KU was formerly a member of the MISO, a non-profit independent transmission system operator that serves the electrical transmission needs of much of the Midwest. KU withdrew from the MISO effective September 1, 2006. KU now contracts with the Tennessee Valley Authority to act as its transmission reliability coordinator and Southwest Power Pool, Inc. to function as its independent transmission operator, pursuant to FERC requirements. See Note 2 of Notes to Financial Statements.

RATES AND REGULATIONS

E.ON, KU's ultimate parent, is a registered holding company under PUHCA 2005. E.ON, its utility subsidiaries, including KU, and certain of its non-utility subsidiaries are subject to extensive regulation by the FERC with respect to numerous matters, including: electric utility facilities and operations, wholesale sales of power and related transactions, accounting practices, issuances and sales of securities, acquisitions and sales of utility properties, payments of dividends out of capital and surplus, financial matters and inter-system sales of non-power goods and services. KU believes that it has adequate authority (including financing authority) under existing FERC orders and regulations to conduct its business and will seek additional authorization when necessary.

In February 2007, KU completed a series of financial transactions that allowed it to cease periodic reporting under the Securities Exchange Act of 1934. See Note 7 of Notes to Financial Statements.

KU is subject to the jurisdiction of the Kentucky Commission, the Virginia Commission, the Tennessee Regulatory Authority and the FERC in virtually all matters related to electric utility regulation, and as such, its accounting is subject to SFAS No. 71, *Accounting for the Effects of Certain Types of Regulation.* Given its competitive position in the marketplace and the status of regulation in Kentucky and Virginia, KU has no plans or intentions to discontinue its application of SFAS No. 71.

For a further discussion of regulatory matters, see Notes 2 and 9 of Notes to Financial Statements.

COAL SUPPLY

Coal-fired generating units provided approximately 96% of KU's net Kwh generation for 2007. The remaining net generation for 2007 was provided by natural gas and oil fueled CT peaking units and a hydroelectric plant. Coal is expected to be the predominant fuel used by KU in the foreseeable future, with natural gas and oil being used for peaking capacity and flame stabilization in coal-fired boilers or in emergencies. KU has no nuclear generating units and has no plans to build any in the foreseeable future.

KU maintains its fuel inventory at levels estimated to be necessary to avoid operational disruptions at its coal-fired generating units. Reliability of coal deliveries can be affected from time to time by a number of factors including fluctuations in demand, coal mine production issues and other supplier or transporter operating difficulties.

KU has entered into coal supply agreements with various suppliers for coal deliveries for 2008 and beyond and normally augments its coal supply agreements with spot market purchases. KU has a coal inventory policy which it believes provides adequate protection under most contingencies.

KU expects to continue purchasing most of its coal, which has sulfur content in the 0.7% - 3.5% range, from western and eastern Kentucky, West Virginia, southern Indiana, southern Illinois and Ohio for the foreseeable future. With the installation of FGDs (SO_2 removal systems), KU expects its use of higher sulfur coal to increase. Coal is delivered to KU generating stations by a mix of transportation modes, including barge, truck and rail.

ENVIRONMENTAL MATTERS

Protection of the environment is a major priority for KU. Federal, state and local regulatory agencies have issued KU permits for various activities subject to air quality, water quality and waste management laws and regulations. See Note 9 of Notes to Financial Statements for additional information.

COMPETITION

At this time, neither the Kentucky General Assembly nor the Kentucky Commission has adopted or approved a plan or timetable for retail electric industry competition in Kentucky. The nature or timing of the ultimate legislative or regulatory actions regarding industry restructuring and their impact on KU, which may be significant, cannot currently be predicted. Some states that have already deregulated have begun discussions that could lead to re-regulation. See Note 2 of Notes to Financial Statements for additional information.

EMPLOYEES AND LABOR RELATIONS

KU had 951 full-time regular employees at December 31, 2007, 152 of which were operating, maintenance and construction employees represented by the IBEW Local 2100 and the United Steelworkers of America ("USWA") Local 9447-01. Effective August 1, 2006, KU and its employees represented by the IBEW Local 2100 entered into a new three-year collective bargaining agreement. The new agreement provides for negotiated increases or changes to wages, benefits or other provisions and for annual wage re-openers. A wage re-opener was negotiated and agreed to in July 2007. KU and employees represented by the USWA Local 9447-01 entered into a three-year collective bargaining agreement in August 2005, with provisions for annual wage re-openers. Wage re-openers were negotiated in July 2006 and July 2007.

OFFICERS OF THE COMPANY

At December 31, 2007: **

Name	Age	Position	Effective Date of Election to Present Position
Victor A. Staffieri	52	Chairman of the Board, President and Chief Executive Officer	May 2001
John R. McCall	64	Executive Vice President, General Counsel, Corporate Secretary and Chief Compliance Officer	July 1994
S. Bradford Rives	49	Chief Financial Officer	September 2003
Martyn Gallus *	43	Senior Vice President – Energy Marketing	December 2000
Chris Hermann	60	Senior Vice President – Energy Delivery	February 2003
Paula H. Pottinger	50	Senior Vice President – Human Resources	January 2006
Paul W. Thompson	50	Senior Vice President – Energy Services	June 2000
Wendy C. Welsh	53	Senior Vice President – Information Technology	December 2000
Michael S. Beer	49	Vice President – Federal Regulation and Policy	September 2004
Lonnie E. Bellar	43	Vice President – State Regulation and Rates	August 2007
Kent W. Blake	41	Vice President – Corporate Planning and Development	August 2007
D. Ralph Bowling	50	Vice President – Power Operations – WKE	August 2002
Laura G. Douglas	58	Vice President – Corporate Responsibility and Community Affairs	November 2007
R. W. Chip Keeling	51	Vice President – Communications	March 2002
John P. Malloy	46	Vice President – Energy Delivery – Retail Business	April 2007
Dorothy E. O'Brien	54	Vice President and Deputy General Counsel – Legal and Environmental Affairs	October 2007
George R. Siemens	58	Vice President – External Affairs	January 2001
P. Greg Thomas	51	Vice President – Energy Delivery – Distribution Operations	April 2007
John N. Voyles, Jr.	53	Vice President – Regulated Generation	June 2003
Daniel K. Arbough	46	Treasurer	December 2000
Valerie L. Scott	51	Controller	January 2005

Officers generally serve in the same capacities at KU and its affiliates, E.ON U.S. and LG&E.
* Mr. Gallus is serving in a position with an international E.ON affiliate, effective January 2008.
** David Sinclair, age 46, was promoted to Vice President – Energy Marketing in January 2008.

Risk Factors

KU is subject to a number of risks, including without limitation, those listed below and elsewhere in this document. Such risks could affect actual results and cause results to differ materially from those expressed in any forward-looking statements made by KU.

The rates that KU charges customers, as well as other aspects of the business, are subject to significant and complex governmental regulation. Federal and state entities regulate many aspects of utility operations, including financial and capital structure matters; siting and construction of facilities; rates, terms and conditions of service and operations; mandatory reliability and safety standards; accounting and cost allocation methodologies; tax matters; acquisition and disposal of utility assets and securities and other matters. Such regulations may subject KU to higher operating costs or increased capital expenditures and failure to comply could result in sanctions or possible penalties. In any rate-setting proceedings, federal or state agencies, intervenors and other permitted parties may challenge KU's rate request and ultimately reduce, alter or limit the rates KU seeks.

Changes in transmission and wholesale power market structures, as well as KU's exit from the MISO, could increase costs or reduce revenues. The resulting changes to transmission and wholesale power market structures and prices are not estimable and may result in unforeseen effects on energy purchases and sales, transmission and related costs or revenues.

Transmission and interstate market activities of KU, as well as other aspects of the business, are subject to significant FERC regulation. KU's business is subject to extensive regulation under the FERC covering matters including rates charged to transmission users and wholesale customers; interstate power market structure; construction and operation of transmission facilities; mandatory reliability standards; standards of conduct and affiliate restrictions and other matters. Existing FERC regulation, changes thereto or issuances of new rules or situations of non-compliance, can affect the earnings, operations or other activities of KU.

KU undertakes significant capital projects and is subject to unforeseen costs, delays or failures in such projects, as well as risk of full recovery of such costs. The completion of these facilities without delays or cost overruns is subject to risks in many areas, including approval and licensing; permitting; construction problems or delays; increases in commodity prices or labor rates; contractor performance; weather and geological issues and political, labor and regulatory developments.

KU's costs of compliance with environmental laws are significant and are subject to continuing changes. Extensive federal, state and local environmental regulations are applicable to KU's air emissions, water discharges and the management of hazardous and solid waste, among other areas; and the costs of compliance or alleged non-compliance cannot be predicted with certainty. Costs may take the form of increased capital or operating and maintenance expenses; monetary fines, penalties or forfeitures or other restrictions.

KU's operating results are affected by weather conditions, including storms and seasonal temperature variations, as well as by significant man-made or accidental disturbances, including terrorism or natural disasters. These weather or man-made factors can significantly affect KU's finances or operations by changing demand levels; causing outages; damaging infrastructure or requiring significant repair costs; affecting capital markets or impacting future growth.

KU is subject to risks regarding potential developments concerning global climate change matters. Such developments could include potential federal or state legislation or industry initiatives limiting GHG emissions; establishing costs or charges on GHG emissions or on fuels relating to such emissions; requiring GHG remediation or sequestration; establishing renewable portfolio standards or generation fleet-diversification requirements to address GHG emissions; promoting energy efficiency and conservation or other measures. KU's generation fleet is predominantly coal-fired and may be highly impacted by developments in this area.

KU's business is concentrated in the Midwest United States, specifically Kentucky. Local and regional economic conditions, such as population growth, industrial growth or expansion and economic development, as well as the operational or financial performance of major industries or customers, can affect the demand for energy.

KU is subject to operational risks relating to its generating plants, transmission facilities and distribution equipment. Operation of power plants, transmission and distribution facilities subjects KU to many risks, including the breakdown or failure of equipment; accidents; labor disputes; delivery/transportation problems; disruptions of fuel supply and performance below expected levels.

KU could be negatively affected by rising interest rates, downgrades to company or bond insurer credit ratings that could impact the Company's bond credit ratings or other negative developments in its ability to access capital markets. In the ordinary course of business, KU is reliant upon adequate long-term and short-term financing means to fund its significant capital expenditures, debt interest or maturities and operating needs. Increases in interest rates could result in increased costs to KU.

KU is subject to commodity price risk, credit risk, counterparty risk and other risks associated with the energy business. General market or pricing developments or failures by counterparties to perform their obligations relating to energy, fuels, other commodities, goods, services or payments could result in potential increased costs to KU.

KU is subject to risks associated with defined benefit retirement plans, health care plans, wages and other employee-related matters. Risks include adverse developments in legislation or regulation, future costs or funding levels, returns on investments, interest rates and actuarial matters, as well as, changing wage levels, whether related to collective bargaining agreements or employment market conditions, ability to attract and retain key personnel and changing costs of providing health care benefits.

Legal Proceedings

Rates and Regulatory Matters

For a discussion of current rates and regulatory matters, including base rate increase proceedings, merger surcredit proceedings, VDT proceedings, TC2 proceedings, Kentucky Commission, FERC and MISO proceedings and other rates or regulatory matters affecting KU, see Notes 2 and 9 of Notes to Financial Statements.

Environmental

For a discussion of environmental matters including additional reductions in SO_2, NOx and other emissions mandated by recent or potential regulations; items regarding notices of violations and other emissions proceedings; global warming or climate change matters and other environmental items affecting KU, see Note 9 of Notes to Financial Statements.

Litigation

For a discussion of litigation matters, see Note 9 of Notes to Financial Statements.

Other

In the normal course of business, other lawsuits, claims, environmental actions and other governmental proceedings arise against KU. To the extent that damages are assessed in any of these lawsuits, KU believes that its insurance coverage is adequate. Management, after consultation with legal counsel, does not anticipate that liabilities arising out of currently pending or threatened lawsuits and claims will have a material adverse effect on KU's financial position or results of operations.

Selected Financial Data

(in millions)	Years Ended December 31				
	2007	2006	2005	2004	2003
Operating revenues	$1,273	$1,210	$1,207	$ 995	$ 892
Net operating income	$ 268	$ 235	$ 202	$ 228	$ 162
Net income	$ 167	$ 152	$ 112	$ 134	$ 91
Total assets	$3,796	$3,148	$2,756	$2,610	$2,505
Long-term obligations (including amounts due within one year)	$1,264	$ 843	$ 746	$ 726	$ 688

Management's Discussion and Analysis and Notes to Financial Statements should be read in conjunction with the above information.

Management's Discussion and Analysis

The following discussion and analysis by management focuses on those factors that had a material effect on KU's financial results of operations and financial condition during 2007 and 2006 and should be read in connection with the financial statements and notes thereto.

Forward Looking Statements

Some of the following discussion may contain forward-looking statements that are subject to risks, uncertainties and assumptions. Such forward-looking statements are intended to be identified in this document by the words "anticipate," "expect," "estimate," "objective," "possible," "potential" and similar expressions. Actual results may materially vary. Factors that could cause actual results to materially differ include: general economic conditions; business and competitive conditions in the energy industry; changes in federal or state legislation; unusual weather; actions by state or federal regulatory agencies; actions by credit rating agencies and other factors described from time to time in KU's reports, including as noted in the Risk Factors section of this report.

RESULTS OF OPERATIONS

The electric utility business is affected by seasonal temperatures. As a result, operating revenues (and associated operating expenses) are not generated evenly throughout the year.

Net Income

Net income in 2007 increased $15 million compared to 2006. The increase was primarily the result of increased retail sales volumes, increased ECR surcharge and decreased purchased power expense. Partially offsetting these items were decreased wholesale sales, higher interest expense, decreased MISO related revenue and decreased equity in earnings of EEI.

Revenues

Revenues in 2007 increased $63 million primarily due to:

- Increased fuel costs ($57 million) billed to customers through the FAC due to increased fuel prices and sales volumes delivered
- Increased sales volumes delivered ($30 million) resulting from a 2% increase in heating degree days and a 46% increase in cooling degree days
- Increased ECR surcharge ($25 million) due to increased recoverable capital spending
- Increased transmission service revenues ($4 million)

These increases were partially offset by:

- Lower wholesale sales ($37 million) due to decreased volumes and lower wholesale market pricing
- Lower MISO related revenue ($16 million) resulting from the exit from the MISO

Expenses

Fuel for electric generation comprises a large component of total operating expenses. Increases or decreases in the cost of fuel are reflected in retail rates through the FAC, subject to the approval of the Kentucky Commission, the Virginia Commission and the FERC.

Fuel for electric generation increased $37 million in 2007 primarily due to:

- Increased cost of fuel burned ($20 million) due to higher coal prices
- Increased generation ($17 million) due to higher demand

Power purchased expense decreased $14 million in 2007 primarily due to:

- Decreased volumes purchased ($19 million) due to increased internal generation
- Increased cost per Mwh of purchases ($5 million) due to higher fuel prices

Other operation and maintenance expenses increased $1 million in 2007 primarily due to increased maintenance expenses ($12 million), partially offset by decreased other operation expenses ($11 million).

Other maintenance expenses increased $12 million in 2007 primarily due to:

- Increased boiler maintenance expense ($7 million)
- Increased electric plant maintenance ($5 million)
- Increased vegetation management expense ($1 million)
- Decreased overhead conductor and devices maintenance ($1 million)

Other operation expenses decreased $11 million in 2007 primarily due to:

- Decreased MISO Day 1 and Day 2 expenses ($16 million) due to the exit from the MISO effective September 1, 2006, and refunds from the MISO for certain charges
- Decreased VDT workforce reduction expense ($3 million) due to completion of VDT amortization in March 2006
- Increased MISO Day 1 expense ($3 million) due to credit received from the MISO for financial transmission rights in 2006
- Increased outside services expense ($3 million)
- Increased wholesale expense ($1 million) due to a recorded credit in April 2006 for a FERC ordered refund from the MISO for charges assessed in excess of the rates in the MISO transmission tariff
- Increased research and development expenses ($1 million)

Equity earnings in EEI decreased $3 million in 2007 primarily due to decreased other electric earnings at EEI, resulting from decreased emission allowance sales in 2007 and increased purchased power expense.

Other income – net increased $5 million in 2007 primarily due to increased other income ($7 million) relating to increased allowance for funds used during construction, gain on disposal of property and increased interest income from bond proceeds on deposit with a trustee, partially offset by increased other expenses ($2 million) relating to penalties.

Interest expense increased $17 million in 2007, primarily due to increased interest expense to affiliated companies resulting from increased affiliate borrowings to fund increased capital additions.

CRITICAL ACCOUNTING POLICIES/ESTIMATES

Preparation of financial statements and related disclosures in compliance with generally accepted accounting principles requires the application of appropriate technical accounting rules and guidance, as well as the use of estimates. The application of these policies necessarily involves judgments regarding future events, including legal and regulatory challenges and anticipated recovery of costs. These judgments could materially impact the financial statements and disclosures based on varying assumptions, which may be appropriate to use. In addition, the financial and operating environment also may have a significant effect, not only on the operation of the business, but on the results reported through the application of accounting measures used in preparing the financial statements and related disclosures, even if the nature of the accounting policies applied has not changed. Specific risks for these critical accounting policies are described in the Notes to Financial Statements. Each of these has a higher likelihood of resulting in materially different reported amounts under different conditions or using different assumptions. Events rarely develop exactly as forecasted and the best estimates routinely require adjustment.

Critical accounting policies and estimates including unbilled revenue, allowance for doubtful accounts, regulatory mechanisms, pension and postretirement benefits and income taxes are detailed in Notes 1, 2, 3, 5, 6 and 9 of Notes to Financial Statements.

Recent Accounting Pronouncements. Recent accounting pronouncements affecting KU are detailed in Note 1 of Notes to Financial Statements.

LIQUIDITY AND CAPITAL RESOURCES

KU uses net cash generated from its operations and external financing (including financing from affiliates) to fund construction of plant and equipment and the payment of dividends. KU believes that such sources of funds will be sufficient to meet the needs of its business in the foreseeable future.

As of December 31, 2007, KU is in a negative working capital position in part because of the classification of certain variable-rate pollution control bonds totaling $33 million that are subject to tender for purchase at the option of the holder as current portion of long-term debt. Credit facilities totaling $35 million are in place to fund such tenders, if necessary. KU has never needed to access these facilities. KU expects to cover any working capital deficiencies with cash flow from operations, money pool borrowings and borrowings from Fidelia.

Operating Activities

Cash provided by operations was $302 million and $223 million in 2007 and 2006, respectively.

The 2007 increase of $79 million was primarily the result of increases in cash due to changes in:

- Earnings, net of non-cash items ($55 million)
- Material and supplies ($33 million) due to lower coal inventories on hand at December 31, 2007
- MISO exit fee ($20 million) due to the MISO exit being completed effective September 1, 2006
- Accrued income taxes ($15 million) due to income tax accrued during 2007 being greater than estimated payments
- ECR recovery ($11 million)
- Prepayments and other current assets ($9 million)
- Other current liabilities ($8 million)
- Other liabilities ($7 million)
- Other regulatory assets ($4 million)
- FAC recovery ($3 million)

These increases were partially offset by cash used for changes in:

- Pension and postretirement funding ($36 million)
- Accounts payable ($26 million)
- Property and other taxes payable ($14 million)
- Accounts receivable ($10 million)

Investing Activities

The primary use of funds for investing activities continues to be for capital expenditures. Net cash used for investing activities increased $382 million in 2007 compared to 2006 primarily due to increased capital expenditures of $395 million, offset by decreased restricted cash of $13 million. Restricted cash represents the escrowed proceeds of the Pollution Control Bonds issued, which are disbursed as qualifying costs are incurred.

Financing Activities

Net cash inflows from financing activities were $422 million and $124 million in 2007 and 2006, respectively. See Note 7 of Notes to Financial Statements for information of redemptions, maturities and issuances of long-term debt.

Future Capital Requirements

KU expects its capital expenditures for the three-year period ending December 31, 2010, to total approximately $1,465 million, consisting primarily of construction estimates for installation of FGDs on Ghent and Brown units totaling approximately $425 million, construction of TC2 totaling approximately $360 million, the Brown ash pond totaling approximately $40 million, a customer care system totaling approximately $25 million and on-going construction related to generation and distribution assets. See Note 9 of Notes to Financial Statements for additional information.

KU's construction program is designed to ensure that there will be adequate capacity and reliability to meet the electric needs of its service area and to comply with environmental regulations. These needs are continually being reassessed and appropriate revisions are made, when necessary, in construction schedules. Future capital requirements may be affected in varying degrees by factors such as electric energy demand load growth, changes in construction expenditure levels, rate actions by regulatory agencies, new legislation, market entry of competing electric power generators, changes in commodity prices and labor rates, changes in environmental regulations and other regulatory requirements. See Contractual Obligations further below and Note 9 of Notes to Financial Statements for current commitments. KU anticipates funding future capital requirements through operating cash flow, debt and/or infusions of capital from its parent.

Regulatory approvals are required for KU to incur additional debt. The Virginia Commission and the FERC authorize the issuance of short-term debt while the Kentucky Commission, the Virginia Commission and the Tennessee Regulatory Authority authorize the issuance of long-term debt. In November 2007, KU received a two-year authorization from the FERC to borrow up to $400 million in short-term funds. KU also has authorization from the Virginia Commission that expires at the end of 2009 allowing short-term borrowing of up to $400 million.

KU's debt ratings as of December 31, 2007, were:

	Moody's	S&P
Pollution control revenue bonds	A2	BBB+
Issuer rating	A2	-
Corporate credit rating	-	BBB+

These ratings reflect the views of Moody's and S&P. A security rating is not a recommendation to buy, sell or hold securities and is subject to revision or withdrawal at any time by the rating agency. See Note 7 of Notes to Financial Statements for a discussion of recent downgrade actions related to the pollution control revenue bonds.

Contractual Obligations

The following is provided to summarize contractual cash obligations for periods after December 31, 2007. KU anticipates cash from operations and external financing will be sufficient to fund future obligations. Future interest obligations cannot be quantified because most of KU's debt is variable rate. See Statements of Capitalization.

(in millions)	Payments Due by Period						
Contractual Cash Obligations	2008	2009	2010	2011	2012	Thereafter	Total
Short-term debt (a)	$ 23	$ -	$ -	$ -	$ -	$ -	$ 23
Long-term debt	-	-	33	-	50	1,181 (b)	1,264
Operating leases (c)	6	5	3	2	2	4	22
Unconditional power purchase obligations (d)	23	25	16	8	9	143	224
Coal and gas purchase obligations (e)	329	146	93	57	57	-	682
Retirement obligations (f)	23	24	23	23	23	124	240
Other obligations (g)	307	79	6	-	-	-	392
Total contractual cash obligations	$711	$279	$174	$90	$141	$1,452	$2,847

(a) Represents borrowings from affiliated company due within one year.
(b) Includes long-term debt of $33 million classified as current liabilities because these bonds are subject to tender for purchase at the option of the holder and to mandatory tender for purchase upon the occurrence of certain events. These bonds mature in 2032. KU does not expect to pay these amounts in 2008.
(c) Represents future operating lease payments.
(d) Represents future minimum payments under OMU and OVEC power purchase agreements through 2010 and 2026, respectively.
(e) Represents contracts to purchase coal and natural gas.
(f) Represents currently projected cash flows for pension, postretirement and other post-employment benefit plans as calculated by the actuary.
(g) Represents construction commitments, including commitments for TC2 and the FGDs.

CONTROLS AND PROCEDURES

The Company is responsible for establishing and maintaining adequate internal control over financial reporting. Internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

The Company has assessed the effectiveness of its internal control over financial reporting as of December 31, 2007. In making this assessment, the Company used the criteria set forth by the Committee of Sponsoring

Organizations of the Treadway Commission in Internal Control - Integrated Framework ("COSO"). The Company has concluded that, as of December 31, 2007, the Company's internal control over financial reporting was effective based on those criteria.

KU is no longer subject to the internal control and other requirements of the Sarbanes-Oxley Act of 2002 and associated rules (the "Act") and consequently has not issued Management's Report on Internal Controls over Financial Reporting pursuant to Section 404 of the Act.

Kentucky Utilities Company
Statements of Income
(Millions of $)

	Years Ended December 31 2007	2006
OPERATING REVENUES:		
Total operating revenues (Note 11)	$1,273	$1,210
OPERATING EXPENSES:		
Fuel for electric generation	461	424
Power purchased (Notes 9 and 11)	168	182
Other operation and maintenance expenses	255	254
Depreciation and amortization (Note 1)	121	115
Total operating expenses	1,005	975
Net operating income	268	235
Equity earnings in EEI (Note 1)	(26)	(29)
Other income – net	(6)	(1)
Interest expense (Notes 7 and 8)	15	15
Interest expense to affiliated companies (Note 11)	41	24
Income before income taxes	244	226
Federal and state income taxes (Note 6)	77	74
Net income	$ 167	$ 152

The accompanying notes are an integral part of these financial statements.

Statements of Retained Earnings
(Millions of $)

	Years Ended December 31 2007	2006
Balance January 1	$ 870	$ 718
Add net income	167	152
Balance December 31	$1,037	$ 870

The accompanying notes are an integral part of these financial statements.

Kentucky Utilities Company
Statements of Comprehensive Income
(Millions of $)

	Years Ended December 31 2007	2006
Net income	$167	$ 152
Additional minimum pension liability adjustment, net of tax expense of $0 and $13 for 2007 and 2006, respectively (Note 5)	-	19
Other comprehensive income, net of tax (Note 12)	-	19
Comprehensive income	$167	$ 171

The accompanying notes are an integral part of these financial statements.

Kentucky Utilities Company
Balance Sheets
(Millions of $)

	December 31 2007	December 31 2006
ASSETS:		
Current assets:		
Cash and cash equivalents (Note 1)	$ -	$ 6
Restricted cash (Note 1)	11	23
Accounts receivable – less reserve of $2 in 2007 and 2006 (Note 1)	172	123
Accounts receivable from affiliated companies (Note 11)	17	50
Materials and supplies (Note 1):		
Fuel (predominantly coal)	42	64
Other materials and supplies	34	34
Prepayments and other current assets	12	18
Total current assets	288	318
Other property and investments (Note 1)	29	25
Utility plant, at original cost (Note 1)	3,868	3,681
Less: reserve for depreciation	1,622	1,553
Total utility plant, net	2,246	2,128
Construction work in progress	1,071	487
Total utility plant and construction work in progress	3,317	2,615
Deferred debits and other assets:		
Regulatory assets (Note 2):		
Pension and postretirement benefits (Notes 1 and 2)	28	64
Other	86	83
Cash surrender value of key man life insurance	37	35
Other assets	11	8
Total deferred debits and other assets	162	190
Total Assets	$3,796	$3,148

The accompanying notes are an integral part of these financial statements.

Kentucky Utilities Company
Balance Sheets (continued)
(Millions of $)

	December 31 2007	2006
LIABILITIES AND EQUITY:		
Current liabilities:		
Current portion of long-term debt (Note 7)	$ 33	$ 141
Notes payable to affiliated companies (Notes 8 and 11)	23	97
Accounts payable	160	83
Accounts payable to affiliated companies (Note 11)	48	87
Customer deposits	20	19
Other current liabilities	28	23
Total current liabilities	312	450
Long-term debt:		
Long-term bonds (Note 7)	300	219
Long-term notes to affiliated company (Note 7)	931	483
Total long-term debt	1,231	702
Deferred credits and other liabilities:		
Accumulated deferred income taxes (Note 6)	285	289
Accumulated provision for pensions and related benefits (Note 5)	83	126
Investment tax credit (Note 6)	55	13
Asset retirement obligations	30	28
Regulatory liabilities (Note 2):		
Accumulated cost of removal of utility plant	310	297
Deferred income taxes	22	27
Other regulatory liabilities	10	6
Other liabilities	23	17
Total deferred credits and other liabilities	818	803
Commitments and contingencies (Note 9)		
COMMON EQUITY:		
Common stock, without par value -		
Authorized 80,000,000 shares, outstanding 37,817,878 shares	308	308
Additional paid-in-capital (Note 11)	90	15
Retained earnings	1,016	854
Undistributed subsidiary earnings	21	16
Total retained earnings	1,037	870
Total common equity	1,435	1,193
Total Liabilities and Equity	$3,796	$3,148

The accompanying notes are an integral part of these financial statements.

Kentucky Utilities Company
Statements of Cash Flows
(Millions of $)

	Years Ended December 31 2007	2006
CASH FLOWS FROM OPERATING ACTIVITIES:		
Net income	$ 167	$ 152
Items not requiring cash currently:		
Depreciation and amortization	121	115
Deferred income taxes-net	(6)	14
Investment tax credit-net	42	11
Provision for pension and postretirement plans	36	4
Other	(7)	2
Change in certain current assets and liabilities:		
Accounts receivable	(16)	(6)
Materials and supplies	22	(11)
Accounts payable	(26)	-
Accrued income taxes	2	(13)
Property and other taxes payable	(4)	10
Prepayments and other current assets	1	(8)
Other current liabilities	10	2
Pension and postretirement funding	(43)	(7)
MISO exit fee	-	(20)
Environmental cost recovery mechanism refundable	(1)	(12)
Other	4	(10)
Net cash provided by operating activities	302	223
CASH FLOWS FROM INVESTING ACTIVITIES:		
Construction expenditures	(742)	(347)
Change in restricted cash	12	(1)
Net cash used for investing activities	(730)	(348)
CASH FLOWS FROM FINANCING ACTIVITIES:		
Long-term borrowings from affiliated company	448	100
Short-term borrowings from affiliated company	289	763
Repayment of short-term borrowings from affiliated company	(363)	(736)
Retirement of first mortgage bonds	(108)	(36)
Issuance of pollution control bonds	81	33
Additional paid-in capital	75	-
Net cash provided by financing activities	422	124
Change in cash and cash equivalents	(6)	(1)
Cash and cash equivalents at beginning of year	6	7
Cash and cash equivalents at end of year	$ -	$ 6
Supplemental disclosures of cash flow information:		
Cash paid during the year for:		
Income taxes	$38	$82
Interest on borrowed money	16	15
Interest to affiliated companies on borrowed money	29	20

The accompanying notes are an integral part of these financial statements.

Kentucky Utilities Company
Statements of Capitalization
(Millions of $)

	December 31 2007	2006
LONG-TERM DEBT (Note 7):		
First mortgage bonds:		
P due May 15, 2007, 7.92% (Note 3)	-	54
Pollution control series:		
10, due November 1, 2024, variable %	-	54
Mercer Co. 2000 Series A, due May 1, 2023, variable %	13	13
Carroll Co. 2002 Series A, due February 1, 2032, variable %	21	21
Carroll Co. 2002 Series B, due February 1, 2032, variable %	2	2
Muhlenberg Co. 2002 Series A, due February 1, 2032, variable %	2	2
Mercer Co. 2002 Series A, due February 1, 2032, variable %	8	8
Carroll Co. 2002 Series C, due October 1, 2032, variable %	96	96
Carroll Co. 2004 Series A, due October 1, 2034, variable %	50	50
Carroll Co. 2005 Series A, due June 1, 2035, variable %	13	13
Carroll Co. 2005 Series B, due June 1, 2035, variable %	13	13
Carroll Co. 2006 Series A, due June 1, 2036, variable %	17	17
Carroll Co. 2006 Series C, due June 1, 2036, variable %	17	17
Carroll Co. 2007 Series A, due February 1, 2026, variable %	18	-
Carroll Co. 2006 Series B, due October 1, 2034, variable %	54	-
Trimble Co. 2007 Series A, due March 1, 2037, variable %	9	-
Notes payable to Fidelia:		
Due November 24, 2010, 4.24%, unsecured	33	33
Due January 16, 2012, 4.39%, unsecured	50	50
Due April 30, 2013, 4.55%, unsecured	100	100
Due August 15, 2013, 5.31%, unsecured	75	75
Due July 8, 2015, 4.735%, unsecured	50	50
Due December 21, 2015, 5.36%, unsecured	75	75
Due October 25, 2016, 5.675% unsecured	50	50
Due June 23, 2036, 6.33%, unsecured	50	50
Due December 19, 2014, 5.45% unsecured	100	-
Due June 20, 2017, 5.98% unsecured	50	-
Due October 25, 2019, 5.71% unsecured	70	-
Due February 7, 2022, 5.69% unsecured	53	-
Due September 14, 2028, 5.96% unsecured	100	-
Due March 30, 2037, 5.86% unsecured	75	-
Total long-term debt outstanding	1,264	843
Less current portion of long-term debt	33	141
Long-term debt	1,231	702
COMMON EQUITY:		
Common stock, without par value -		
Authorized 80,000,000 shares, outstanding 37,817,878 shares	308	308
Additional paid-in-capital (Note 11)	90	15
Retained earnings	1,016	854
Undistributed subsidiary earnings	21	16
Total retained earnings	1,037	870
Total common equity	1,435	1,193
Total capitalization	$2,666	$1,895

The accompanying notes are an integral part of these financial statements.

Note 1 - Summary of Significant Accounting Policies

KU, incorporated in Kentucky in 1912 and in Virginia in 1991, is a regulated public utility engaged in the generation, transmission, distribution and sale of electric energy in Kentucky, Virginia and Tennessee. KU provides electricity to approximately 506,000 customers in 77 counties in central, southeastern and western Kentucky, to approximately 30,000 customers in 5 counties in southwestern Virginia and 5 customers in Tennessee. KU's coal-fired electric generating stations produce most of KU's electricity. The remainder is generated by a hydroelectric power plant and natural gas and oil fueled CTs. In Virginia, KU operates under the name Old Dominion Power Company. KU also sells wholesale electric energy to 12 municipalities.

KU is a wholly-owned subsidiary of E.ON U.S., formerly known as LG&E Energy LLC. E.ON U.S. is an indirect wholly-owned subsidiary of E.ON, a German corporation, making KU an indirect wholly-owned subsidiary of E.ON. KU's affiliate, LG&E, is a regulated public utility engaged in the generation, transmission, distribution and sale of electric energy and the distribution and sale of natural gas in Kentucky.

Certain reclassification entries have been made to the previous years' financial statements to conform to the 2007 presentation with no impact on net assets, liabilities and capitalization or previously reported net income and cash flows.

Regulatory Accounting. KU is subject to SFAS No. 71, under which regulatory assets are created based on expected recovery from customers in future rates to defer costs that would otherwise be charged to expense. Likewise, regulatory liabilities are created based on expected return to customers in future rates to defer credits that would otherwise be reflected as income, or, in the case of costs of removal, are created to match long-term future obligations arising from the current use of assets. The accounting for regulatory assets and liabilities is based on specific ratemaking decisions or precedent for each item as prescribed by the FERC, the Kentucky Commission or the Virginia Commission. See Note 2, Rates and Regulatory Matters, for additional detail regarding regulatory assets and liabilities.

Cash and Cash Equivalents. KU considers all highly liquid investments with an original maturity of three months or less to be cash equivalents.

Restricted Cash. Proceeds from bond issuances for environmental equipment (primarily related to the installation of FGDs) are held in trust pending expenditure for qualifying assets.

Allowance for Doubtful Accounts. The allowance for doubtful accounts is based on the ratio of the amounts charged-off during the last twelve months to the retail revenues billed over the same period multiplied by the retail revenues billed over the last four months. Accounts with no payment activity are charged-off after four months, although collection efforts continue thereafter.

Materials and Supplies. Fuel and other materials and supplies inventories are accounted for using the average-cost method. Emission allowances are included in other materials and supplies and are not currently traded by KU. At December 31, 2007 and 2006, the emission allowances inventory was less than $1 million and approximately $2 million, respectively.

Other Property and Investments. Other property and investments on the balance sheets consists of KU's investment in EEI, economic development loans provided to various communities in KU's service territory, KU's investment in OVEC, funds related to KU's long-term purchased power contract with OMU and non-utility plant.

Although KU holds investment interests in OVEC and EEI, it is not the primary beneficiary, therefore, neither are consolidated into KU's financial statements. KU and 11 other electric utilities are participating owners of OVEC, located in Piketon, Ohio. OVEC owns and operates two power plants that burn coal to generate electricity, Kyger Creek Station in Ohio and Clifty Creek Station in Indiana. Pursuant to current contractual arrangements, KU's share of OVEC's output is 2.5%, approximately 55 Mw of generation capacity.

As of December 31, 2007 and 2006, KU's investment in OVEC totaled less than $1 million and is accounted for under the cost method of accounting. KU's maximum exposure to loss as a result of its involvement with OVEC is limited to the value of its investment. In the event of the inability of OVEC to fulfill its power provision requirements, KU anticipates substituting such power supply with either owned generation or market purchases and believes it would generally recover associated incremental costs through regulatory rate mechanisms. See Note 9, Commitments and Contingencies, for further discussion of developments regarding KU's ownership interests and power purchase rights.

KU owns 20% of the common stock of EEI, which owns and operates a 1,162-Mw generating station in southern Illinois. Prior to 2006, KU was entitled to take 20% of the available capacity of the station under a pricing formula comparable to the cost of other power generated by KU. This contract governing the purchases from EEI terminated on December 31, 2005. Since December 31, 2005, EEI has sold power under general market-based pricing and terms. KU has not contracted with EEI for power under the new arrangements, but maintains its 20% ownership in the common stock of EEI. Replacement power for the EEI capacity has been largely provided by KU generation.

KU's investment in EEI is accounted for under the equity method of accounting and, as of December 31, 2007 and 2006, totaled $23 million and $18 million, respectively. KU's direct exposure to loss as a result of its involvement with EEI is generally limited to the value of its investment.

Utility Plant. KU's utility plant is stated at original cost, which includes payroll-related costs such as taxes, fringe benefits and administrative and general costs. Construction work in progress has been included in the rate base for determining retail customer rates in Kentucky. KU has not recorded a significant allowance for funds used during construction.

The cost of plant retired or disposed of in the normal course of business is deducted from plant accounts and such cost is charged to the reserve for depreciation. When complete operating units are disposed of, appropriate adjustments are made to the reserve for depreciation and gains and losses, if any, are recognized.

Depreciation and Amortization. Depreciation is provided on the straight-line method over the estimated service lives of depreciable plant. The amounts provided were approximately 3.2% in 2007 and 3.1% in 2006 of average depreciable plant. Of the amount provided for depreciation at December 31, 2007 and 2006, approximately 0.5% was related to the retirement, removal and disposal costs of long lived assets.

Unamortized Debt Expense. Debt expense is capitalized in deferred debits and amortized using the straight line method, which approximates the effective interest method, over the lives of the related bond issues.

Income Taxes. Income taxes are accounted for under SFAS No. 109, *Accounting for Income Taxes* and FIN 48, *Accounting for Uncertainty in Income Taxes, an Interpretation of SFAS No. 109*. In accordance with these statements, deferred tax assets and liabilities are recognized for the future tax consequences attributable to differences between the financial statement carrying amounts of existing assets and liabilities and their respective tax bases, as measured by enacted tax rates that are expected to be in effect in the periods when the deferred tax assets and liabilities are expected to be settled or realized. Significant judgment is required in determining the provision for income taxes, and there are transactions for which the ultimate tax outcome is uncertain. FIN 48 prescribes a recognition threshold and measurement attribute for the financial statement recognition and measurement of a tax position taken or expected to be taken in a tax return. . Uncertain tax positions are analyzed periodically and adjustments are made when events occur to warrant a change. See Note 6, Income Taxes.

Deferred Income Taxes. Deferred income taxes are recognized at currently enacted tax rates for all material temporary differences between the financial reporting and income tax bases of assets and liabilities.

Investment Tax Credits. The EPAct 2005 added Section 48A to the Internal Revenue Code, which provides for an investment tax credit to promote the commercialization of advanced coal technologies that will generate electricity in an environmentally responsible manner. KU and LG&E received an investment tax credit related to TC2, for more details see Note 6, Income Taxes. Investment tax credits prior to 2006 resulted from provisions of the tax law that permitted a reduction of KU's tax liability based on credits for construction expenditures. Deferred investment tax credits are being amortized to income over the estimated lives of the related property that gave rise to the credits.

Revenue Recognition. Revenues are recorded based on service rendered to customers through month-end. KU accrues an estimate for unbilled revenues from each meter reading date to the end of the accounting period based on allocating the daily system net deliveries between billed volumes and unbilled volumes. The allocation is based on a daily ratio of the number of meter reading cycles remaining in the month to the total number of meter reading cycles in each month. Each day's ratio is then multiplied by each day's system net deliveries to determine an estimated billed and unbilled volume for each day of the accounting period. The unbilled revenue estimates included in accounts receivable were $59 million and $42 million at December 31, 2007 and 2006, respectively.

Fuel Costs. The cost of fuel for generation is charged to expense as used.

Management's Use of Estimates. The preparation of financial statements in conformity with generally accepted accounting principles requires management to make estimates and assumptions that affect the reported assets and liabilities and disclosure of contingent items at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. Accrued liabilities, including legal and environmental, are recorded when they are probable and estimable. Actual results could differ from those estimates.

Recent Accounting Pronouncements. The following are recent accounting pronouncements affecting KU:

<u>SFAS No. 160</u>

In December 2007, the FASB issued SFAS No. 160, *Noncontrolling Interests in Consolidated Financial Statements,* which is effective for fiscal years, and interim periods within those fiscal years, beginning on or after December 15, 2008. The objective of this statement is to improve the relevance, comparability and transparency of financial information in a reporting entity's consolidated financial statements. The Company expects the adoption of SFAS No. 160 to have no impact on its statements of operations, financial position and cash flows.

SFAS No. 159

In February 2007, the FASB issued SFAS No. 159, *The Fair Value Option for Financial Assets and Financial Liabilities – Including an Amendment of FASB Statement No. 115*. SFAS No. 159 permits entities to choose to measure many financial instruments and certain other assets and liabilities at fair value on an instrument-by-instrument basis (the fair value option). Unrealized gains and losses on items for which the fair value option has been elected are to be recognized in earnings at each subsequent reporting date. SFAS No. 159 is effective for fiscal years beginning after November 15, 2007. SFAS No. 159 was adopted effective January 1, 2008 and had no impact on the statements of operations, financial position and cash flows.

SFAS No. 157

In September 2006, the FASB issued SFAS No. 157, *Fair Value Measurements*, which, except as described below, is effective for fiscal years beginning after November 15, 2007. This statement defines fair value, establishes a framework for measuring fair value in generally accepted accounting principles and expands disclosures about fair value measurements. SFAS No. 157 does not expand the application of fair value accounting to new circumstances. In February 2008, the FASB issued FASB Staff Position 157-2, *Effective Date of FASB Statement No. 157,* which delays the effective date of SFAS No. 157 for all nonfinancial assets and liabilities, except those that are recognized or disclosed at fair value in the financial statements on a recurring basis (at least annually), to fiscal years beginning after November 15, 2008 and interim periods within those fiscal years. SFAS No. 157 was adopted effective January 1, 2008, except as it applies to those nonfinancial assets and liabilities, and had no impact on the statements of operations, financial position and cash flows, however, the Company will provide additional disclosures relating to its financial derivatives, AROs and pension assets as required in 2008.

FIN 48

In July 2006, the FASB issued FIN 48 which clarifies the accounting for the uncertainty of income tax positions recognized in an enterprise's financial statements in accordance with SFAS No. 109. This interpretation prescribes a recognition threshold and measurement attribute for the financial statement recognition and measurement of a tax position taken or expected to be taken in a tax return.

The evaluation of a tax position in accordance with FIN 48 is a two-step process. The first step is recognition based on the determination of whether it is "more likely than not" that a tax position will be sustained upon examination. The second step is to measure a tax position that meets the "more likely than not" threshold. The tax position is measured as the amount of potential benefit that exceeds 50% likelihood of being realized.

FIN 48 is effective for fiscal years beginning after December 15, 2006, and was adopted effective January 1, 2007. The impact of FIN 48 on the statements of operations, financial position and cash flows was not material.

Note 2 - Rates and Regulatory Matters

KU is subject to the jurisdiction of the Kentucky Commission, the Virginia Commission, the Tennessee Regulatory Authority and the FERC in virtually all matters related to electric utility regulation, and as such, its accounting is subject to SFAS No. 71. Given its competitive position in the marketplace and the status of regulation in Kentucky and Virginia, KU has no plans or intentions to discontinue its application of SFAS No. 71.

Rate Case

In December 2003, KU filed an application with the Kentucky Commission requesting an adjustment in KU's rates. The revenue increase requested was $58 million. In June 2004, the Kentucky Commission issued an Order approving an increase in KU's base rates of approximately $46 million (7%). The rate increase took effect on July 1, 2004.

Final proceedings took place during the first quarter of 2006 concerning the sole remaining open issue relating to state income tax rates used in calculating the granted rate increase. On March 31, 2006, the Kentucky Commission issued an Order resolving this issue in KU's favor consistent with the original rate increase order.

Regulatory Assets and Liabilities

The following regulatory assets and liabilities were included in the balance sheets as of December 31:

(in millions)	2007	2006
ARO	$ 24	$ 22
MISO exit	20	20
FAC	17	16
Unamortized loss on bonds	10	10
ECR	11	10
Other	4	5
Subtotal	86	83
Pension and postretirement benefits	28	64
Total regulatory assets	$ 114	$ 147
Accumulated cost of removal of utility plant	$ 310	$ 297
Deferred income taxes - net	22	27
Other	10	6
Total regulatory liabilities	$ 342	$ 330

KU does not currently earn a rate of return on the FAC regulatory asset, which is a separate recovery mechanism with recovery within twelve months. No return is earned on the pension and postretirement benefits regulatory asset which represents the changes in funded status of the plans. The Company will seek recovery of this asset in future proceedings with the Kentucky and Virginia Commissions. No return is currently earned on the ARO asset. This regulatory asset will be offset against the associated regulatory liability, ARO asset and ARO liability at the time the underlying asset is retired. The MISO exit amount represents the costs relating to the withdrawal from MISO membership. KU will seek recovery of this asset in future proceedings with the Kentucky and Virginia Commissions. KU currently earns a rate of return on the remaining regulatory assets. Other regulatory assets include VDT costs, the merger surcredit and deferred storm costs. Other regulatory liabilities include DSM and MISO costs included in base rates that will be netted against costs of withdrawing from the MISO in the next rate case.

ARO. A summary of KU's net ARO assets, regulatory assets, liabilities and cost of removal established under FIN 47, *Accounting for Conditional Asset Retirement Obligations, an Interpretation of SFAS No. 143,* and SFAS No. 143, *Accounting for Asset Retirement Obligations,* follows:

(in millions)	ARO Net Assets	ARO Liabilities	Regulatory Assets	Regulatory Liabilities	Accumulated Cost of Removal	Cost of Removal Depreciation
As of December 31, 2005	$ 6	$(27)	$20	$ (2)	$ 2	$ 1
ARO accretion	-	(1)	1	-	-	-
ARO depreciation	(1)	-	1	-	-	-
As of December 31, 2006	5	(28)	22	(2)	2	1
ARO accretion	-	(2)	2	-	-	-
As of December 31, 2007	$ 5	$(30)	$24	$ (2)	$ 2	$ 1

Pursuant to regulatory treatment prescribed under SFAS No. 71, an offsetting regulatory credit was recorded in depreciation and amortization in the income statement of $2 million in 2007 and 2006 for the ARO accretion and depreciation expense. KU AROs are primarily related to the final retirement of assets associated with generating units. For assets associated with AROs, the removal cost accrued through depreciation under regulatory accounting is established as a regulatory liability pursuant to regulatory treatment prescribed under SFAS No. 71. There were no FIN 47 net asset additions during 2007 or 2006. For the years ended December 31, 2007 and 2006, KU recorded less than $1 million of depreciation expense related to the cost of removal of ARO related assets. An offsetting regulatory liability was established pursuant to regulatory treatment prescribed under SFAS No. 71.

KU transmission and distribution lines largely operate under perpetual property easement agreements which do not generally require restoration upon removal of the property. Therefore, under SFAS No. 143, no material asset retirement obligations are recorded for transmission and distribution assets.

MISO Exit. Following receipt of applicable FERC, Kentucky Commission and other regulatory orders, KU withdrew from the MISO effective September 1, 2006. Specific proceedings regarding the costs and benefits of the MISO and exit matters had been underway since July 2003. Since the exit from the MISO, KU has been operating under a FERC-approved open access-transmission tariff. KU now contracts with the Tennessee Valley Authority to act as its transmission Reliability Coordinator and Southwest Power Pool, Inc. to function as Independent Transmission Organization, pursuant to FERC requirements.

KU and the MISO have agreed upon overall calculation methods for the contractual exit fee to be paid by the Company following its withdrawal. In October 2006, KU paid approximately $20 million to the MISO pursuant to an invoice regarding the exit fee and made related FERC compliance filings. The Company's payment of this exit fee amount was with reservation of its rights to contest the amount, or components thereof, following a continuing review of its calculation and supporting documentation. In December 2006, KU provided notice to the MISO of its disagreement with the calculation of the exit fee. KU and the MISO have resolved their dispute regarding the calculation of the exit fee and, in November 2007, filed an application with the FERC for approval of a recalculation agreement. In March 2008, the FERC approved the parties' recalculation of the exit fee, and the approved agreement provides KU with an immediate recovery of $1 million and will provide an estimated $3 million over the next eight years for credits realized from other payments the MISO will receive, plus interest. Orders of the Kentucky Commission approving the Company's exit from the MISO have authorized the establishment of a regulatory asset for the exit fee, subject to adjustment for possible future MISO credits, and a regulatory liability for certain revenues associated with former MISO administrative charges, which may continue to be collected via base rates. The treatment of the regulatory asset and liability will be determined in KU's next rate case, however, the Company historically has received approval to recover and refund regulatory assets and liabilities.

FAC. KU's retail rates contain an FAC, whereby increases and decreases in the cost of fuel for generation are reflected in the rates charged to retail customers. The FAC allows the Company to adjust customers' accounts for the difference between the fuel cost component of base rates and the actual fuel cost, including transportation costs. Refunds to customers occur if the actual costs are below the embedded cost component. Additional charges to customers occur if the actual costs exceed the embedded cost component. The amount of the regulatory asset or liability is the amount that has been under- or over-recovered due to timing or adjustments to the mechanism.

The Kentucky Commission requires public hearings at six-month intervals to examine past fuel adjustments, and at two-year intervals to review past operations of the fuel clause and transfer of the then current fuel adjustment charge or credit to the base charges.

In January 2008, the Kentucky Commission initiated a routine examination of KU's FAC for the six-month period May 1, 2007 through October 31, 2007. Data discovery is ongoing and a public hearing is scheduled in March 2008.

In August 2007, the Kentucky Commission initiated a routine examination of KU's FAC for the six-month period of November 1, 2006 through April 30, 2007. Data discovery has concluded and a public hearing was held in October 2007. The Kentucky Commission issued an Order in January 2008, approving the charges and credits billed through the FAC during the review period.

In December 2006, the Kentucky Commission initiated its periodic two-year review of KU's past operations of the fuel clause and transfer of fuel costs from the FAC to base rates for November 1, 2004 through October 31, 2006. In March 2007, the KIUC challenged KU's recovery of approximately $5 million in aggregate fuel costs KU incurred during a period prior to its exit from the MISO and requested the Kentucky Commission disallow this amount. A public hearing was held in May 2007. In October 2007, the Kentucky Commission issued its Order approving the calculation and application of KU's FAC charges and fuel procurement practices and indicated that KU was in compliance with the provisions of Administrative Regulation 807 KAR 5:5056. The Kentucky Commission further approved KU's recommendation for the transfer of fuel cost from the FAC to base rates. In November 2007, the KIUC filed a petition for rehearing, claiming the Kentucky Commission misinterpreted the KIUC's arguments in the proceeding. In the same month, the Kentucky Commission issued an Order denying the KIUC's request for rehearing. An appeal was not filed by the KIUC.

In July 2006, the Kentucky Commission initiated a six-month review of the FAC for KU for the period of November 1, 2005 through April 30, 2006. The Kentucky Commission issued an Order in November 2006, approving the charges and credits billed through the FAC during the review period.

In January 2003, the Kentucky Commission reviewed KU's FAC for the six-month period ended October 31, 2001. The Kentucky Commission ordered KU to reduce its fuel costs for purposes of calculating its FAC by less than $1 million. At issue was the purchase of approximately 102,000 tons of coal from Western Kentucky Energy Corp., a non-regulated affiliate, for use at KU's Ghent facility. The Kentucky Commission further ordered that an independent audit be conducted to examine operational and management aspects of both KU's and LG&E's fuel procurement functions. The final report's recommendations, issued in February 2004, related to documentation and process improvements. Management Audit Action Plans were agreed upon by KU and the Kentucky Commission Staff in the second quarter of 2004, and resulted in Audit Progress Reports being filed by KU with the Kentucky Commission. In February 2007, the Kentucky Commission staff indicated that KU fully complied with all audit recommendations and that no further reports are required.

KU also employs an FAC mechanism for Virginia customers that uses an average fuel cost factor based primarily on projected fuel costs. The fuel cost factor may be adjusted annually for over or under collections of fuel costs from the previous year. In February 2007, KU filed an application with the Virginia Commission seeking approval of an increase of approximately $4 million in its fuel cost factor to reflect higher fuel costs incurred and under-collected during 2006, and anticipated higher fuel costs to be incurred in 2007. The Virginia Commission approved KU's request in April 2007. In February 2008, KU filed an application with the Virginia Commission seeking approval of a decrease of 0.599 cents/KWh in its fuel cost factor applicable during the billing period April 2008 through March 2009. The decrease was requested because KU has fully recovered its under-recovered fuel expenses from the prior periods.

Unamortized Loss on Bonds. The costs of early extinguishment of debt, including call premiums, legal and other expenses, and any unamortized balance of debt expense are amortized using the straight line method, which approximates the effective interest method, over the life of either replacement debt (in the case of refinancing) or the original life of the extinguished debt.

ECR. Kentucky law permits KU to recover the costs of complying with the Federal Clean Air Act, including a return of operating expenses, and a return of and on capital invested, through the ECR mechanism. The amount of the regulatory asset or liability is the amount that has been under- or over-recovered due to timing or adjustments to the mechanism.

In September 2007, the Kentucky Commission initiated six-month and two-year reviews for periods ending October 31, 2006 and April 30, 2007, respectively, of KU's environmental surcharge. Data discovery concluded in December 2007, and all parties to the case submitted requests with the Kentucky Commission to waive rights to a hearing on this matter. The case is submitted for decision and an order is anticipated in the second quarter of 2008.

In June 2006, KU filed an application for a CCN to construct an SCR at the Ghent station and to amend its ECR plan with the Kentucky Commission seeking approval to recover investments in environmental upgrades at the Company's generating facilities. The estimated capital cost of the upgrades for the years 2008 through 2010 is approximately $125 million, of which approximately $115 million is for the Air Quality Control System at TC2. A final Order was issued by the Kentucky Commission in December 2006, approving all expenditures and investments as submitted. In October 2007, KU met with the Kentucky Commission and other interested parties to discuss the status of the Ghent Unit 2 SCR construction. KU informed the Kentucky Commission that construction of the Ghent Unit 2 SCR was not going to commence before the CCN expired in December 2007, due to a change in the economics for the project. The CCN expired in December 2007, and KU has delayed construction of the Ghent Unit 2 SCR.

In April 2006, the Kentucky Commission initiated six-month and two-year reviews of KU's environmental surcharge for six-month periods ending July 2003, January 2004, January 2005, July 2005 and January 2006 and for the two-year period ending July 2004. A final Order was received in January 2007, approving the charges and credits billed through the ECR during the review period as well as approving billing adjustments, a roll-in to base rates, revisions to the monthly surcharge filing and the rate of return on capital.

VDT. In December 2001, the Kentucky Commission issued an Order approving a settlement agreement allowing KU to set up a regulatory asset of $54 million for workforce reduction costs and begin amortizing it over a five-year period starting in April 2001. Some employees rescinded their participation in the voluntary enhanced severance program which, along with the non-recurring charge of $7 million for FERC and Virginia jurisdictions, thereby decreased the charge to the regulatory asset from $64 million to $54 million. The Order reduced revenues by approximately $11 million through a surcredit on bills to ratepayers over the same five-year period, reflecting a sharing (40% to the ratepayers and 60% to KU) of savings as stipulated by KU, net of amortization costs of the workforce reduction. The five-year VDT amortization period expired in March 2006.

As part of the settlement agreement in the rate case, in September 2005, KU filed with the Kentucky Commission a plan for the future ratemaking treatment of the VDT surcredit and costs. In February 2006, the AG, KIUC and KU reached a settlement agreement on the future ratemaking treatment of the VDT surcredits and costs and subsequently submitted a joint motion to the Kentucky Commission to approve the unanimous settlement agreement. Under the terms of the settlement agreement, the VDT surcredit will continue at the current level until such time as KU files for a change in base rates. The Kentucky Commission issued an Order in March 2006, approving the settlement agreement.

Merger Surcredit. As part of the LG&E Energy merger with KU Energy Corporation in 1998, KU estimated non-fuel savings over a ten-year period following the merger. Costs to achieve these savings were deferred and amortized over a five-year period pursuant to regulatory orders. In approving the merger, the Kentucky Commission adopted KU's proposal to reduce its retail customers' bills based on one-half of the estimated merger-related savings, net of deferred and amortized amounts, over a five-year period. The surcredit mechanism provides that 50% of the net non-fuel cost savings estimated to be achieved from the merger be provided to ratepayers through a monthly bill credit, and 50% be retained by KU over a five-year period. In that same order, the Kentucky Commission required KU, after the end of the five-year period, to present a plan for sharing with ratepayers the then-projected non-fuel savings associated with the merger. KU submitted this filing in January 2003, proposing to continue to share with ratepayers, on a 50%/50% basis, the estimated fifth-year gross level of non-fuel savings associated with the merger. In October 2003, the Kentucky Commission issued an Order approving a settlement agreement reached with the parties in the case. According to the Order, KU's merger surcredit would remain in place for another five-year term beginning July 1, 2003, the merger savings would continue to be shared 50% with ratepayers and 50% with shareholders and KU would file a plan for the merger surcredit six months before its expiration.

In December 2007, KU submitted to the Kentucky Commission its plan to allow the merger surcredit to terminate as scheduled on June 30, 2008. The Kentucky Commission has not issued a procedural schedule for this proceeding.

Deferred Storm Costs. Based on an Order from the Kentucky Commission in June 2004, KU reclassified from maintenance expense to a regulatory asset, $4 million related to costs not reimbursed from the 2003 ice storm. These costs will be amortized through June 2009. KU earns a return of these amortized costs, which are included in KU's jurisdictional operating expenses.

Pension and Postretirement Benefits. KU adopted SFAS No. 158, *Employers' Accounting for Defined Benefit Pension and Other Postretirement Plans,* in 2006. This statement requires employers to recognize the over-funded or under-funded status of a defined benefit pension and postretirement plan as an asset or liability in the balance sheet and to recognize through comprehensive income the changes in the funded status in the year in which the changes occur. Under SFAS No. 71, KU can defer recoverable costs that would otherwise be charged to expense or equity by non-regulated entities. Current rate recovery in Kentucky and Virginia is based on SFAS No. 87, *Employers' Accounting for Pensions,* and SFAS No. 106, *Employers' Accounting for Postretirement Benefits Other than Pensions,* both of which were amended by SFAS No. 158. Regulators have been clear and consistent with their historical treatment of such rate recovery, therefore, KU has recorded a regulatory asset representing the probable recovery of the portion of the change in funded status of the pension and postretirement plans that is expected to be recovered. The regulatory asset will be adjusted annually as prior service cost and actuarial gains and losses are recognized in net periodic benefit cost.

Accumulated Cost of Removal of Utility Plant. As of December 31, 2007 and 2006, KU has segregated the cost of removal, previously embedded in accumulated depreciation, of $310 million and $297 million, respectively, in accordance with FERC Order No. 631. This cost of removal component is for assets that do not have a legal ARO under SFAS No. 143. For reporting purposes in the balance sheets, KU has presented this cost of removal as a regulatory liability pursuant to SFAS No. 71.

Deferred Income Taxes – Net. Deferred income taxes represent the future income tax effects of recognizing the regulatory assets and liabilities in the income statement. Deferred income taxes are recognized at currently enacted tax rates for all material temporary differences between the financial reporting and income tax bases of assets and liabilities.

DSM. KU's rates contain a DSM provision. The provision includes a rate mechanism that provides for concurrent recovery of DSM costs and provides an incentive for implementing DSM programs. The provision allows KU to recover revenues from lost sales associated with the DSM programs based on program plan engineering estimates and post-implementation evaluations.

In July 2007, KU and LG&E filed an application with the Kentucky Commission requesting an order approving enhanced versions of the existing DSM programs along with the addition of several new cost effective programs. The total annual budget for these programs is approximately $26 million, an increase over the existing annual budget of approximately $10 million. Data discovery concluded in November 2007, and the Community Action Council ("CAC") for Lexington-Fayette, Bourbon, Harrison and Nicholas counties and the Kentucky Association for Community Action ("KACA"), filed a motion for hearing. In January 2008, the CAC and KACA filed a motion with the Kentucky Commission to withdraw the request because the parties reached a settlement. The Kentucky Commission is allowing the current tariffs to remain in effect until a final order is issued.

Other Regulatory Matters

Utility Competition in Virginia. The Commonwealth of Virginia passed the Virginia Electric Utility Restructuring Act in 1999. This act gave Virginia customers the ability to choose their electric supplier. Rates are capped at current levels through December 2010. The Virginia Commission will continue to require each Virginia utility to make annual filings of either a base rate change or an Annual Informational Filing consisting of a set of standard financial schedules. The Virginia Commission Staff will issue a Staff Report regarding the individual utility's financial performance during the historic 12-month period. The Staff Report can lead to an adjustment in rates, but through December 2010, rates are subject to the capped rate period and essentially "frozen". In April 2007, Virginia passed legislation terminating this competitive market and commencing re-regulation of utility rates in Virginia. The new act will end the cap on rates at the end of 2008, rather than through December 2010, and end customer choice for most consumers in the applicable regions of the state. Thereafter, a hybrid model of regulation is expected to apply in Virginia, whereby utility rates would be reviewed every two years and a utility's rate of return on equity shall not be set lower than the average of the rates of return for other regional utilities, with certain caps, floors or adjustments. The legislation was effective in July 2007, and also includes a 10% nonbinding goal for renewable power generation by 2022, as well as incentives for new generation, including renewables. Under the legislation, KU retains an existing exemption from customer choice and other restructuring activities as applicable to KU's limited service territory in Virginia. However, subject to future developments, KU may or may not undertake such a rate proceeding in the first six months of 2009 based on calendar year 2008 financial data under the hybrid model of regulation, or make biennial rate filings with the Virginia Commission thereafter.

Regional Reliability Council. KU has changed its regional reliability council membership from the Reliability First Corporation to the SERC Reliability Corporation ("SERC"), effective January 1, 2007. Regional reliability councils are industry consortiums that promote, coordinate and ensure the reliability of the bulk electric supply systems in North America.

TC2 CCN Application. A CCN application for construction of the new, base-load, coal fired unit TC2, which will be jointly owned by KU and LG&E, was approved by the Kentucky Commission in November 2005, and initial CCN applications for three transmission lines were approved in September 2005 and May 2006. In August 2006, KU obtained dismissal of a judicial review of such CCN approvals by certain property owners. In December 2007, the Kentucky Court of Appeals reversed and remanded the lower Court's dismissal. Both parties have filed for reconsideration of elements of the appellate court's ruling. The transmission lines are also subject to routine regulatory filings and the right-of-way acquisition process. See Note 9, Commitments and Contingencies, for further discussion regarding the TC2 air permit.

Ghent FGD Inquiry. In October 2006, the Kentucky Commission commenced an inquiry into elements of KU's planned construction of one of its three new FGDs at the Ghent generating station. The proceeding requested, and KU provided, additional information regarding configuration details, expenditures and the proposed construction sequence applicable to future construction phases of the Ghent FGD project. In January 2007, the Kentucky Commission issued an Order completing its inquiry in the matter and confirming its approval of KU's construction plan. The Order also provided general guidance for jurisdictional utilities regarding applicable information and data requirements for future CCN applications and subsequent proceedings.

Market-Based Rate Authority. In July 2006, the FERC issued an Order in KU's market-based rate proceeding accepting KU's further proposal to address certain market power issues the FERC had claimed would arise upon an exit from the MISO. In particular, KU received permission to sell power at market-based rates at the interface of control areas in which it may be deemed to have market power, subject to a restriction that such power not be collusively re-sold back into such control areas. However, restrictions exist on sales by KU of power at market-based rates in the KU/LG&E and Big Rivers Electric Corporation control areas. In June 2007, the FERC issued Order No. 697 implementing certain reforms to market-based rate regulations, including restrictions similar to those previously in place for KU's power sales at control area interfaces. As a condition of receiving and retaining market-based rate authority, KU must comply with applicable affiliate restrictions set forth in FERC's regulation.

FERC Audit Results. In July 2006, the FERC issued a final report under a routine audit that its Office of Enforcement (formerly its Office of Market Oversight and Investigations) had conducted regarding the compliance of E.ON U.S. and its subsidiaries, including KU, under the FERC's standards of conduct and codes of conduct requirements, as well as other areas. The final report contained certain findings calling for improvements in E.ON U.S. and its subsidiaries' structures, policies and procedures relating to transmission, generation dispatch, energy marketing and other practices. E.ON U.S. and its subsidiaries have agreed to certain corrective actions and have submitted procedures related to such corrective actions to the FERC. The corrective actions are in the nature of organizational and operational improvements as described above and are not expected to have a material adverse impact on the Company's results of operations or financial condition.

Mandatory Reliability Standards. As a result of EPAct 2005, certain formerly voluntary reliability standards became mandatory in June 2007, and authority was delegated to various regional reliability organizations ("RRO") by the Electric Reliability Organization, which was authorized by the FERC to enforce compliance with such standards, including promulgating new standards. Failure to comply with mandatory reliability standards can subject a registered entity to sanctions, including potential fines of up to $1 million per day as well as non-monetary penalties, depending upon the circumstances of the violation. KU is a member of the SERC, which acts as KU's RRO. The SERC is currently assessing KU's compliance with certain existing mitigation plans resulting from a prior RRO's audit of various reliability standards. While KU believes itself to be in substantial compliance with the mandatory reliability standards generally, KU cannot predict the outcome of the current SERC proceeding or of other analysis which may be conducted regarding compliance with particular reliability standards.

IRP. Integrated resource planning regulations in Kentucky require major utilities to make triennial IRP filings with the Kentucky Commission. In April 2005, KU and LG&E filed their 2005 joint IRP with the Kentucky Commission. The IRP provides historical and projected demand, resource and financial data, and other operating performance and system information. The AG and the KIUC were granted intervention in the IRP proceeding. The Kentucky Commission issued its staff report with no substantive issues noted and closed the case by Order in February 2006. KU and LG&E will submit the next joint triennial filing in April 2008.

PUHCA 2005. E.ON, KU's ultimate parent, is a registered holding company under PUHCA 2005. E.ON, its utility subsidiaries, including KU, and certain of its non-utility subsidiaries, are subject to extensive regulation by the FERC with respect to numerous matters, including: electric utility facilities and operations, wholesale sales of power and related transactions, accounting practices, issuances and sales of securities, acquisitions and sales of utility properties, payments of dividends out of capital and surplus, financial matters and inter-system sales of non-power goods and services. KU believes that it has adequate authority (including financing authority) under existing FERC orders and regulations to conduct its business and will seek additional authorization when necessary.

EPAct 2005. The EPAct 2005 was enacted in August 2005. Among other matters, this comprehensive legislation contains provisions mandating improved electric reliability standards and performance; granting enhanced civil penalty authority to the FERC; providing economic and other incentives relating to transmission, pollution control and renewable generation assets; increasing funding for clean coal generation incentives; repealing the Public Utility Holding Company Act of 1935; enacting PUHCA 2005 and expanding FERC jurisdiction over public utility holding companies and related matters via the Federal Power Act and PUHCA 2005.

In February 2006, the Kentucky Commission initiated an administrative proceeding to consider the requirements of the EPAct 2005, Subtitle E Section 1252, Smart Metering, which concerns time-based metering and demand response, and Section 1254, Interconnections. EPAct 2005 requires each state regulatory authority to conduct a formal investigation and issue a decision on whether or not it is appropriate to implement certain Section 1252, Smart Metering standards within eighteen months after the enactment of EPAct 2005 and to commence consideration of Section 1254, Interconnection standards within one year after the enactment of EPAct 2005. Following a public hearing with all Kentucky jurisdictional electric utilities, in December 2006, the Kentucky Commission issued an Order in this proceeding indicating that the EPAct 2005 Section 1252, Smart Metering and Section 1254, Interconnection standards should not be adopted. However, all five Kentucky Commission jurisdictional utilities are required to file real-time pricing pilot programs for their large commercial and industrial customers. KU developed a real-time pricing pilot for large industrial and commercial customers and filed the details of the plan with the Kentucky Commission in April 2007. Data discovery concluded in July 2007, and no parties to the case requested a hearing. In February 2008, the Kentucky Commission issued an Order approving the real-time pricing pilot program proposed by KU for implementation within approximately eight months. KU will notify the Kentucky Commission 10 days prior to the actual implementation date and will file annual reports on the program within 90 days of each plan year-end for the 3-year pilot period.

Green Energy Riders. In February 2007, KU and LG&E filed a Joint Application and Testimony for Proposed Green Energy Riders. The AG and KIUC were granted full intervention. In May 2007, a Kentucky Commission Order was issued authorizing KU to establish Small and Large Green Energy Riders, allowing customers to contribute funds to be used for the purchase of renewable energy credits.

Home Energy Assistance Program. In July 2007, KU filed an application with the Kentucky Commission for the establishment of a new Home Energy Assistance program. During September 2007, the Kentucky Commission approved KU's new five-year program as filed, effective in October 2007. The program terminates in September 2012, and is funded through a $0.10 per month meter charge.

Depreciation Study. In December 2007, KU filed a depreciation study with the Kentucky Commission requesting a change in the depreciation rates as required by a previous Order. An adjustment to the depreciation rates is dependent on an order being received by the Kentucky Commission, the timing of which cannot currently be determined.

Note 3 - Financial Instruments

The cost and estimated fair values of KU's non-trading financial instruments as of December 31 follow:

	2007		2006	
(in millions)	Carrying Value	Fair Value	Carrying Value	Fair Value
Long-term debt (including current portion of $33 million)	$333	$333	$360	$360
Long-term debt from affiliate	$931	$996	$483	$487

All of the above valuations reflect prices quoted by exchanges except for the loans from affiliate which are fair valued using accepted valuation models. The fair values of cash and cash equivalents, accounts receivable, cash surrender value of key man life insurance, accounts payable and notes payable are substantially the same as their carrying values.

Interest Rate Swaps (hedging derivatives). KU has used over-the-counter interest rate swaps to hedge exposure to market fluctuations in certain of its debt instruments. Pursuant to Company policy, use of these financial instruments has been intended to mitigate risk, earnings and cash flow volatility and was not speculative in nature. Management had designated all of the interest rate swaps as hedge instruments. Financial instruments designated as fair value hedges and the underlying hedged items are periodically marked to market with the resulting net gains and losses recorded directly into net income. Upon termination of any fair value hedge, the resulting gain or loss is recorded into net income.

KU had no outstanding interest rate swap agreements at December 31, 2007. KU was party to an interest rate swap agreement with a notional amount of $53 million as of December 31, 2006. The interest rate swap was terminated in February 2007, when the underlying debt was defeased. Under this swap agreement, KU paid variable rates based on the London Interbank Offer Rate averaging 7.44% and received fixed rates averaging 7.92% at December 31, 2006. The swap agreement in effect at December 31, 2006 had been designated as a fair value hedge. The fair value designation was assigned because the underlying fixed rate debt had a firm future commitment. For 2007 and 2006, the effect of marking these financial instruments and the underlying debt to market resulted in pre-tax gains of less than $1 million recorded in interest expense.

Interest rate swaps hedge interest rate risk on the underlying debt under SFAS No. 133, *Accounting for Derivative Instruments and Hedging Activities,* as amended, in addition to swaps being marked to market, the item being hedged must also be marked to market. Consequently, at December 31, 2006, KU's debt reflects a mark-to-market adjustment of less than $1 million.

Energy Risk Management Activities (non-hedging derivatives). KU conducts energy trading and risk management activities to maximize the value of power sales from physical assets it owns. Energy trading activities are principally forward financial transactions to hedge price risk and are accounted for on a mark-to-market basis in accordance with SFAS No. 133, as amended.

The table below summarizes KU's energy trading and risk management activities:

(in millions)	2007	2006
Fair value of contracts at beginning of period, net asset	$ 1	$ 1
Unrealized gains and losses recognized at contract inception during the period	-	-
Realized gains and losses recognized during the period	-	1
Changes in fair values attributable to changes in valuation techniques and assumptions	(1)	(2)
Other unrealized gains and losses and changes in fair values	-	1
Fair value of contracts at end of period, net asset	$ -	$ 1

No changes to valuation techniques for energy trading and risk management activities occurred during 2007 or 2006. Changes in market pricing, interest rate and volatility assumptions were made during both years. All contracts outstanding at December 31, 2007 and 2006, have a maturity of less than one year and are valued using prices actively quoted for proposed or executed transactions or quoted by brokers.

KU maintains policies intended to minimize credit risk and revalues credit exposures daily to monitor compliance with those policies. At December 31, 2007, 100% of the trading and risk management commitments were with counterparties rated BBB-/Baa3 equivalent or better.

KU hedges the price volatility of its forecasted electric wholesale sales with the sales of market-traded electric forward contracts for periods of less than one year. Hedge accounting treatment has not been elected for these transactions, and therefore gains and losses are shown in the statements of income in other income – net. No material pre-tax gains and losses resulted in 2007. Pre-tax gains of $1 million resulted in 2006.

Note 4 - Concentrations of Credit and Other Risk

Credit risk represents the accounting loss that would be recognized at the reporting date if counterparties failed to perform as contracted. Concentrations of credit risk (whether on- or off-balance sheet) relate to groups of customers or counterparties that have similar economic or industry characteristics that would cause their ability to meet contractual obligations to be similarly affected by changes in economic or other conditions.

KU's customer receivables and revenues arise from deliveries of electricity to approximately 506,000 customers in over 600 communities and adjacent suburban and rural areas in 77 counties in central, southeastern and western Kentucky, to approximately 30,000 customers in five counties in southwestern Virginia and 5 customers in Tennessee. For the years ended December 31, 2007 and 2006, 100% of total revenue was derived from electric operations.

Effective August 1, 2006, KU and its employees represented by the IBEW Local 2100 entered into a new three-year collective bargaining agreement. The new agreement provides for negotiated increases or changes to wages, benefits or other provisions and for annual wage re-openers. A wage re-opener was negotiated in July 2007. KU and its employees represented by the USWA Local 9447-01 entered into a three-year collective bargaining agreement effective August 2005, with authorized annual wage re-openers. The employees represented by these two bargaining units comprise approximately 16% of KU's workforce at December 31, 2007. Wage re-openers were negotiated in July 2006, and July 2007.

Note 5 - Pension and Other Postretirement Benefit Plans

KU has both funded and unfunded non-contributory defined benefit pension plans and other postretirement benefit plans that together cover substantially all of its employees. The healthcare plans are contributory with participants' contributions adjusted annually. KU uses December 31 as the measurement date for its plans.

Obligations and Funded Status. The following tables provide a reconciliation of the changes in the plans' benefit obligations and fair value of assets over the two-year period ending December 31, 2007, and a statement of the funded status as of December 31 for KU's sponsored defined benefit plans:

(in millions)	Pension Benefits		Other Postretirement Benefits	
	2007	2006	2007	2006
Change in benefit obligation				
Benefit obligation at beginning of year	$ 303	$ 318	$ 88	$ 95
Service cost	6	6	2	2
Interest cost	17	17	5	5
Benefits paid, net of retiree contributions	(19)	(19)	(5)	(5)
Actuarial gain and other	(23)	(19)	(14)	(9)
Benefit obligation at end of year	$ 284	$ 303	$ 76	$ 88
Change in plan assets				
Fair value of plan assets at beginning of year	$ 253	$ 247	$ 12	$ 9
Actual return on plan assets	17	26	-	1
Employer contributions	13	-	6	7
Benefits paid, net of retiree contributions	(19)	(19)	(5)	(5)
Administrative expenses and other	-	(1)	-	-
Fair value of plan assets at end of year	$ 264	$ 253	$ 13	$ 12
Funded status at end of year	$ (20)	$ (50)	$ (63)	$ (76)

Amounts Recognized in Statement of Financial Position. The following tables provide the amounts recognized in the balance sheets and information for plans with benefit obligations in excess of plan assets as of December 31:

(in millions)	Pension Benefits		Other Postretirement Benefits	
	2007	2006	2007	2006
Regulatory assets	$ 37	$ 59	$ (9)	$ 5
Accrued benefit liability (non-current)	(20)	(50)	(63)	(76)

Additional year-end information for plans with accumulated benefit obligations in excess of plan assets:

(in millions)	Pension Benefits		Other Postretirement Benefits	
	2007	2006	2007	2006
Benefit obligation	$ 284	$ 303	$ 76	$ 88
Accumulated benefit obligation	243	258	-	-
Fair value of plan assets	264	253	13	12

Components of Net Periodic Benefit Cost. The following table provides the components of net periodic benefit cost for the plans:

(in millions)	Pension Benefits		Other Postretirement Benefits	
	2007	2006	2007	2006
Service cost	$ 6	$ 6	$ 2	$ 2
Interest cost	17	17	5	5
Expected return on plan assets	(21)	(20)	(1)	(1)
Amortization of prior service costs	1	1	-	1
Amortization of actuarial loss	2	4	-	-
Amortization of transitional obligation	-	-	-	1
Benefit cost at end of year	$ 5	$ 8	$ 6	$ 8

The assumptions used in the measurement of KU's pension benefit obligation are shown in the following table:

	2007	2006
Weighted-average assumptions as of December 31:		
Discount rate	6.66%	5.96%
Rate of compensation increase	5.25%	5.25%

The discount rate is based on the November Mercer Pension Discount Yield Curve, adjusted by the basis point change in the Moody's Corporate Aa Bond Rate in December.

The assumptions used in the measurement of KU's net periodic benefit cost are shown in the following table:

	2007	2006
Discount rate	5.90%	5.50%
Expected long-term return on plan assets	8.25%	8.25%
Rate of compensation increase	5.25%	5.25%

To develop the expected long-term rate of return on assets assumption, KU considered the current level of expected returns on risk free investments (primarily government bonds), the historical level of the risk premium associated with the other asset classes in which the portfolio is invested and the expectations for future returns of each asset class. The expected return for each asset class was then weighted based on the target asset allocation to develop the expected long-term rate of return on assets assumption for the portfolio.

The following describes the effects on pension benefits by changing the major actuarial assumptions discussed above:

- A 1% change in the assumed discount rate could have an approximate $30 million positive or negative impact to the 2007 accumulated benefit obligation and an approximate $40 million positive or negative impact to the 2007 projected benefit obligation.
- A 25 basis point change in the expected rate of return on assets would have an approximate $1 million positive or negative impact on 2007 pension expense.

Assumed Healthcare Cost Trend Rates. For measurement purposes, a 9% annual increase in the per capita cost of covered healthcare benefits was assumed for 2007. The rate was assumed to decrease gradually to 5% by 2015 and remain at that level thereafter.

Assumed healthcare cost trend rates have a significant effect on the amounts reported for the healthcare plans. A 1% change in assumed healthcare cost trend rates would have resulted in an increase or decrease of less than $1 million on the 2007 total of service and interest costs components and an increase or decrease of $4 million in year-end 2007 postretirement benefit obligations.

Expected Future Benefit Payments and Medicare Subsidy Receipts. The following list provides the amount of expected future benefit payments, which reflect expected future service and the estimated gross amount of Medicare subsidy receipts:

(in millions)	Pension Plans	Other Postretirement Benefits	Medicare Subsidy Receipts
2008	$ 18	$ 6	$ (1)
2009	18	7	(1)
2010	17	7	(1)
2011	17	7	(1)
2012	17	7	(1)
2013-17	90	37	(3)

Plan Assets. The following table shows KU's weighted-average asset allocation by asset category at December 31:

Pension Plans	Target Range	2007	2006
Equity securities	45% - 75%	57%	61%
Debt securities	30% - 50%	43%	39%
Other	0% - 10%	0%	0%
Totals		100%	100%

The investment policy of the pension plans was developed in conjunction with financial consultants, investment advisors and legal counsel. The goal of the investment policy is to preserve the capital of the fund and maximize investment earnings. The return objective is to exceed the benchmark return for the policy index comprised of the following: Russell 3000 Index, MSCI-EAFE Index, Lehman Aggregate and Lehman U.S. Long Government/Credit Bond Index in proportions equal to the targeted asset allocation.

Evaluation of performance focuses on a long-term investment time horizon of at least three to five years or a complete market cycle. The assets of the pension plans are broadly diversified within different asset classes (equities, fixed income securities and cash equivalents).

To minimize the risk of large losses in a single asset class, no more than 5% of the portfolio will be invested in the securities of any one issuer with the exclusion of the U.S. government and its agencies. The equity portion of the fund is diversified among the market's various subsections to diversify risk, maximize returns and avoid undue exposure to any single economic sector, industry group or individual security. The equity subsectors include, but are not limited to, growth, value, small capitalization and international.

In addition, the overall fixed income portfolio may have an average weighted duration, or interest rate sensitivity which is within +/- 20% of the duration of the overall fixed income benchmark. Foreign bonds in the aggregate shall not exceed 10% of the total fund. The portfolio may include a limited investment of up to 20% in below investment grade securities provided that the overall average portfolio quality remains "AA" or better. The below investment grade securities include, but are not limited to, medium-term notes, corporate debt, non-dollar and emerging market debt and asset backed securities. The cash investments should be in securities that either are of short maturities (not to exceed 180 days) or readily marketable with modest risk.

Derivative securities are permitted only to improve the portfolio's risk/return profile, to modify the portfolio's duration or to reduce transaction costs and must be used in conjunction with underlying physical assets in the portfolio. Derivative securities that involve speculation, leverage, interest rate anticipation, or any undue risk whatsoever are not deemed appropriate investments.

The investment objective for the postretirement benefit plan is to provide current income consistent with stability of principal and liquidity while maintaining a stable net asset value of $1.00 per share. The postretirement funds are invested in a prime cash money market fund that invests primarily in a portfolio of short-term, high-quality fixed income securities issued by banks, corporations and the U.S. government.

Contributions. KU made a discretionary contribution to the pension plan of $13 million in January 2007. After this payment, KU's pension plan assets are in excess of the December 31, 2007 accumulated benefit obligation.

In addition, KU made contributions to other postretirement benefit plans of $6 million and $7 million in 2007 and 2006, respectively. In 2008, KU anticipates making voluntary contributions to fund the Voluntary Employee Beneficiary Association trusts to match the annual postretirement expense and funding the 401(h) plan up to the maximum amount allowed by law.

Pension Legislation. The Pension Protection Act of 2006 was enacted in August 2006. The new rules are generally effective for plan years beginning after 2008. Among other matters, this comprehensive legislation contains provisions applicable to defined benefit plans which generally (i) mandate 100% funding of current liabilities within seven years; (ii) increase tax-deduction levels regarding contributions; (iii) revise certain actuarial assumptions, such as mortality tables and discount rates; and (iv) raise federal insurance premiums and other fees for under-funded and distressed plans. The legislation also contains similar provisions relating to defined-contribution plans and qualified and non-qualified executive pension plans and other matters.

Thrift Savings Plans. KU has a thrift savings plan under section 401(k) of the Internal Revenue Code. Under the plan, eligible employees may defer and contribute to the plan a portion of current compensation in order to provide future retirement benefits. KU makes contributions to the plan by matching a portion of the employee contributions. The costs of this matching were $2 million for 2007 and 2006.

Note 6 - Income Taxes

A United States consolidated income tax return is filed by E.ON U.S.'s direct parent, E.ON US Investments Corp., for each tax period. Each subsidiary of the consolidated tax group, including KU, will calculate its separate income tax for the tax period. The resulting separate-return tax cost or benefit will be paid to or received from the parent company or its designee. KU also files income tax returns in various state jurisdictions. With few exceptions, KU is no longer subject to U.S. federal income tax examinations for years before 2004. Statutes of limitations related to 2004 and later returns are still open. Tax years 2005, 2006 and 2007 are under audit by the IRS with the 2007 return being examined under an IRS pilot program named "Compliance Assurance Process". This program accelerates the IRS's review to the actual calendar year applicable to the return and ends 90 days after the return is filed.

KU adopted the provisions of FIN 48 effective January 1, 2007. At the date of adoption, KU had less than $1 million of unrecognized tax benefits, primarily related to federal income taxes. If recognized, the less than $1 million of unrecognized tax benefits would reduce the effective income tax rate. Additions and reductions of uncertain tax positions during 2007 were less than $1 million.

Possible amounts of uncertain tax positions for KU that may decrease within the next 12 months total less than $1 million and are based on the expiration of statutes during 2008.

KU, upon adoption of FIN 48, adopted a new financial statement classification for interest and penalties. Prior to the adoption of FIN 48, KU recorded interest and penalties for income taxes on the income statements in income tax expense and in the taxes accrued balance sheet account, net of tax. Upon adoption of FIN 48, interest is recorded as interest expense and penalties are recorded as operating expenses on the income statement and accrued expenses in the balance sheets, on a pre-tax basis. Interest of less than $1 million was accrued for 2007 and 2006 based on IRS and Kentucky Department of Revenue large corporate interest rates for underpayment of taxes. No penalties were accrued by KU upon adoption of FIN 48 or through December 31, 2007.

Components of income tax expense are shown in the table below:

(in millions)		2007	2006
Current	- federal	$ 28	$ 51
	- state	13	11
Deferred	- federal – net	(5)	-
	- state – net	(1)	1
Investment tax credit – deferred		43	12
Amortization of investment tax credit		(1)	(1)
Total income tax expense		$ 77	$ 74

Current federal income tax expense decreased and investment tax credit – deferred increased primarily due to the recording of investment tax credits of $43 million and $12 million at December 31, 2007 and 2006, respectively, as discussed below.

In June 2006, KU and LG&E filed a joint application with the U.S. Department of Energy ("DOE") requesting certification to be eligible for investment tax credits applicable to the construction of TC2. The EPAct 2005 added Section 48A to the Internal Revenue Code, which provides for an investment tax credit to promote the commercialization of advanced coal technologies that will generate electricity in an environmentally responsible manner. KU's and LG&E's application requested up to the maximum amount of "advanced coal project" credit allowed per taxpayer, or $125 million, based on an estimate of 15% of projected qualifying TC2 expenditures. In November 2006, the DOE and the IRS announced that KU and LG&E were selected to receive the tax credit. A final IRS certification required to obtain the investment tax credit was received in August 2007. KU's portion of the TC2 tax credit will be approximately $100 million over the construction period and will be amortized to income over the life of the related property beginning when the facility is placed in service. Based on eligible construction expenditures incurred, KU recorded investment tax credits of $43 million and $12 million in 2007 and 2006, respectively, decreasing current federal income taxes.

In September 2007, KU received Order 2007-00178 from the Kentucky Commission approving the accounting of the investment tax credit. In March 2008, certain groups filed suit in federal court in North Carolina against the DOE and IRS claiming the investment tax credit program was violative of certain environmental laws and demanded relief, including suspension or termination of the program. KU is not able to predict the ultimate outcome of this proceeding.

Components of net deferred tax liabilities included in the balance sheets are shown below:

(in millions)	2007	2006
Deferred tax liabilities:		
Depreciation and other plant-related items	$292	$291
Regulatory assets and other	40	37
Total deferred tax liabilities	332	328
Deferred tax assets:		
Income taxes due to customers	9	10
Pensions and related benefits	17	11
Liabilities and other	23	23
Total deferred tax assets	49	44
Net deferred income tax liability	$283	$284
Balance sheet classification		
Current assets	$ (2)	$ (5)
Non-current liabilities	285	289
Net deferred income tax liability	$283	$284

A reconciliation of differences between the statutory U.S. federal income tax rate and KU's effective income tax rate follows:

	2007	2006
Statutory federal income tax rate	35.0%	35.0%
State income taxes, net of federal benefit	3.4	3.9
Reduction of income tax accruals	(0.4)	(0.5)
Qualified production deduction	(1.2)	(0.4)
EEI dividend	(2.9)	(3.4)
Amortization of investment tax credit	(0.4)	(0.5)
Other differences	(1.9)	(1.4)
Effective income tax rate	31.6%	32.7%

The EEI dividend for 2007 and 2006 reflects tax benefits associated with the receipt of dividends from KU's investment in EEI. Subsequent to an EEI management decision regarding changes in the distribution of EEI's previous earnings, KU elected to provide deferred taxes for all book and tax temporary differences in this investment.

Other differences primarily relate to excess deferred taxes which reflect the benefits of deferred taxes reversing at tax rates that differ from statutory rates and various other permanent differences.

H. R. 4520, known as the "American Jobs Creation Act of 2004", allows electric utilities to take a deduction for qualified production activities income starting in 2005.

Kentucky House Bill 272, also known as "Kentucky's Tax Modernization Plan", was signed into law in March 2005. This bill contains a number of changes in Kentucky's tax system, including the reduction of the Corporate income tax rate from 8.25% to 7% effective January 1, 2005, and a further reduction to 6% effective January 1, 2007. As a result of the income tax rate changes, KU's deferred tax reserve amount will exceed its actual deferred tax liability attributable to existing temporary differences, since the new statutory rates are lower than rates when the deferred tax liability originated. In December 2006, KU received approval from the Kentucky Commission to establish and amortize a regulatory liability of $11 million for these net excess deferred income tax balances. KU will amortize these depreciation-related excess deferred income tax balances under the average rate assumption method which matches the amortization of the excess deferred income taxes with the life of the timing differences to which they relate. Excess deferred income tax balances related to non-depreciation timing differences were expensed in 2006 due to their immaterial amount. There were no additional adjustments in 2007.

KU expects to have adequate levels of taxable income to realize its recorded deferred tax assets.

Note 7 - Long-Term Debt

As of December 31, 2007 and 2006, long-term debt and the current portion of long-term debt consist primarily of pollution control bonds and long-term loans from affiliated companies as summarized below.

(in millions)	Stated Interest Rates	Maturities	Principal Amounts
Outstanding at December 31, 2007:			
Noncurrent portion	Variable – 6.33%	2010-2037	$1,231
Current portion	Variable	2032	$ 33
Outstanding at December 31, 2006:			
Noncurrent portion	Variable – 6.33%	2010-2036	$ 702
Current portion	Variable – 7.92%	2007-2032	$ 141

Pollution control series bonds are obligations of KU issued in connection with tax-exempt pollution control revenue bonds issued by various governmental entities, principally counties in Kentucky. A loan agreement obligates KU to make debt service payments to the county that equate to the debt service due from the county on the related pollution control revenue bonds. Until a series of financing transactions was completed during February 2007, the county's debt was also secured by an equal amount of KU's first mortgage bonds that were pledged to the trustee for the pollution control revenue bonds that match the terms and conditions of the county's debt, but require no payment of principal and interest unless KU defaults on the loan agreement. Proceeds from bond issuances for environmental equipment (primarily related to the installation of FGDs) are held in trust pending expenditure for qualifying assets. At December 31, 2007, and 2006, KU had $11 million and $23 million, respectively, of bond proceeds in trust, included in restricted cash in the balance sheets.

Several of the KU pollution control bonds are insured by monoline bond insurers whose ratings have been under pressure due to exposures relating to insurance of sub-prime mortgages. At December 31, 2007, KU had an aggregate $333 million of outstanding pollution control indebtedness, of which $300 million is in the form of insured auction rate securities wherein interest rates are reset either weekly or every 35 days via an auction process. Beginning in late 2007, the interest rates on these insured bonds began to increase due to investor concerns about the creditworthiness of the bond insurers. In 2008, interest rates have continued to increase, and the Company has experienced "failed auctions" when there are insufficient bids for the bonds. When there is a failed auction, the interest rate is set pursuant to a formula stipulated in the indenture which can be as high as 15%. During 2007, the average rate on the auction rate bonds was 3.96%, whereas the average rate in January and February of 2008 was 4.72%. The instruments governing these auction rate bonds permit KU to convert the bonds to other interest rate modes, such as various short-term variable rates, long-term fixed rates or intermediate-term fixed rates that are reset infrequently. In the first quarter of 2008, the ratings of the Carroll County 2004 Series A bonds were downgraded from AAA to AA and subsequently to A by S&P and from Aaa to A2 by Moody's, and the Carroll County 2006 Series C bonds were downgraded from Aaa to A2 by Moody's and from AAA to A- by S&P due to downgrades of the bond insurer. In February 2008, KU issued a notice to bondholders of its intention to convert the Carroll County 2007 Series A bonds and the Trimble County 2007 Series A bonds from the auction rate mode to a fixed interest rate mode, as permitted under the loan documents. In March 2008, KU will issue notices to bondholders of its intention to convert the Carroll County 2006 Series C bonds and the Mercer County 2000 Series A bonds from the auction mode to a weekly interest rate mode, as permitted under the loan documents. KU expects to purchase such bonds and hold some or all such bonds until a later date, including potential further conversion, remarketings or refinancings. Uncertainty in markets relating to auction rate securities or steps KU has taken or may take to mitigate such uncertainty, such as additional conversions, subsequent restructurings or redemptions and refinancings, could result in KU incurring increased interest expense, transaction expenses or other costs and fees or experiencing reduced liquidity relating to existing or future pollution control financing structures. See Note 13, Subsequent Events.

All of KU's first mortgage bonds were released and terminated in February 2007. Only the tax-exempt pollution control revenue bonds issued by the counties remain. Under the provisions for certain of KU's variable-rate pollution control bonds, the bonds are subject to tender for purchase at the option of the holder and to mandatory tender for purchase upon the occurrence of certain events, causing the bonds to be classified as current portion of long-term debt in the balance sheets. The average annualized interest rate for these bonds during 2007 and 2006 was 3.72% and 3.56%, respectively.

At December 31, 2006, KU had an interest rate swap used to hedge KU's underlying debt obligations. The swap hedged specific debt issuances and, consistent with management's designation, was accorded hedge accounting treatment. The swap effectively converted the fixed rate obligation on KU's first mortgage bond Series P to variable-rate. At December 31, 2006, the remaining swap had a notional value of $53 million. The swap was terminated in February 2007, when the underlying bond was defeased. See Note 3, Financial Instruments.

Redemptions and maturities of long-term debt for 2007 and 2006 are summarized below:

($ in millions) Year	Description	Principal Amount	Rate	Secured/ Unsecured	Maturity
2007	Pollution control bonds	$ 54	Variable	Secured	2024
2007	First mortgage bonds	$ 54	7.92%	Secured	2007
2006	First mortgage bonds	$ 36	5.99%	Secured	2006

Issuances of long-term debt for 2007 and 2006 are summarized below:

($ in millions)

Year	Description	Principal Amount	Rate	Secured/ Unsecured	Maturity
2007	Pollution control bonds	$ 54	Variable	Unsecured	2034
2007	Pollution control bonds	$ 18	Variable	Unsecured	2026
2007	Pollution control bonds	$ 9	Variable	Unsecured	2037
2007	Due to Fidelia	$ 53	5.69%	Unsecured	2022
2007	Due to Fidelia	$ 75	5.86%	Unsecured	2037
2007	Due to Fidelia	$ 50	5.98%	Unsecured	2017
2007	Due to Fidelia	$100	5.96%	Unsecured	2028
2007	Due to Fidelia	$ 70	5.71%	Unsecured	2019
2007	Due to Fidelia	$100	5.45%	Unsecured	2014
2006	Pollution control bonds	$ 17	Variable	Unsecured	2036
2006	Pollution control bonds	$ 17	Variable	Unsecured	2036
2006	Due to Fidelia	$ 50	5.675%	Unsecured	2016
2006	Due to Fidelia	$ 50	6.33%	Unsecured	2036

In February 2007, KU completed a series of financial transactions impacting its periodic reporting requirements. The $54 million Pollution Control Series 10 bond was refinanced and replaced with a new unsecured tax-exempt bond of the same amount maturing in 2034. The $53 million Series P bond was defeased and replaced with an intercompany loan totaling $53 million from Fidelia. In conjunction with the defeasance, the Company terminated the related interest rate swap. Fidelia also agreed to eliminate the second lien on its two secured loans. Pursuant to the terms of the remaining tax-exempt bonds, the first mortgage bonds were cancelled and the underlying lien on substantially all of KU's assets was released following the completion of these steps. KU no longer has any secured debt and is no longer subject to periodic reporting under the Securities Exchange Act of 1934.

Long-term debt maturities for KU are shown in the following table:

(in millions)		
2008 - 2009	$ -	
2010	33	
2011	-	
2012	50	
Thereafter	1,181	(a)
Total	$1,264	

(a) Includes long-term debt of $33 million classified as current liabilities because these bonds are subject to tender for purchase at the option of the holder and to mandatory tender for purchase upon the occurrence of certain events. These bonds mature in 2032. KU does not expect to pay these amounts in 2008.

Note 8 - Notes Payable and Other Short-Term Obligations

KU participates in an intercompany money pool agreement wherein E.ON U.S. and/or LG&E make funds available to KU at market-based rates (based on an index of highly rated commercial paper issues) up to $400 million.

($ in millions)	Total Money Pool Available	Amount Outstanding	Balance Available	Average Interest Rate
December 31, 2007	$400	$23	$377	4.75%
December 31, 2006	$400	$97	$303	5.25%

As of December 31, 2007 and 2006, E.ON U.S. maintained a revolving credit facility totaling $150 million and $200 million, respectively, with an affiliated company, E.ON North America, Inc., to ensure funding availability for the money pool. The balance is as follows:

($ in millions)	Total Available	Amount Outstanding	Balance Available	Average Interest Rate
December 31, 2007	$150	$ 62	$88	4.97%
December 31, 2006	$200	$102	$98	5.49%

During June 2007, KU entered into a short-term bilateral line of credit totaling $35 million. During the third quarter of 2007, KU extended the maturity date on this facility to June 2012. There was no outstanding balance under this facility at December 31, 2007.

The covenants under this revolving line of credit include:

- The debt/total capitalization ratio must be less than 70%
- E.ON must own at least 66.667% of voting stock of KU directly or indirectly
- The corporate credit rating of the Company must be at or above BBB- and Baa3 as determined by S&P and Moody's
- A limitation on disposing of assets aggregating more than 15% of total assets as of December 31, 2006

Note 9 - Commitments and Contingencies

Operating Leases. KU leases office space, office equipment and vehicles and accounts for these leases as operating leases. In addition, KU reimburses LG&E for a portion of the lease expense paid by LG&E for KU's usage of office space leased by LG&E. Total lease expense was $6 million for 2007 and 2006. The future minimum annual lease payments for operating leases for years subsequent to December 31, 2007, are shown in the following table:

(in millions)	
2008	$ 6
2009	5
2010	3
2011	2
2012	2
Thereafter	4
Total	$22

Owensboro Contract Litigation. In May 2004, the City of Owensboro, Kentucky and OMU commenced a suit now removed to the U.S. District Court for the Western District of Kentucky, against KU concerning a long-term power supply contract (the "OMU Agreement") with KU. The dispute involves interpretational differences regarding issues under the OMU Agreement, including various payments or charges between KU and OMU and rights concerning excess power, termination and emissions allowances. The complaint seeks in excess of $6 million in damages in connection with one of its claims for periods prior to 2004, plus damages in an unspecified amount for later-occurring periods on that claim and for other claims. OMU has additionally requested injunctive and other relief, including a declaration that KU is in material breach of the contract. KU has filed an answer in that court denying the OMU claims and presenting counterclaims and amended such filing in January 2007, to include further counterclaims alleging additional damages. During 2005, the FERC declined KU's application to exercise exclusive jurisdiction on matters. In July 2005, the district court resolved a summary judgment motion made by KU in OMU's favor, ruling that a contractual provision grants OMU the ability to terminate the contract without cause upon four years' prior notice, for which ruling KU retains certain rights to appeal. A motion to reconsider that ruling is presently pending before the Court. The parties are continuing various discovery proceedings, as well as settlement negotiations. A trial date has been set for October 2008. In May 2006, OMU issued a notification of its intent to terminate the OMU agreement contract in May 2010, without cause, absent any earlier relief which may be permitted by the proceeding. The Company is currently unable to determine the final outcome of this matter.

Sale and Leaseback Transaction. KU is a participant in a sale and leaseback transaction involving its 62% interest in two jointly owned CTs at KU's E.W. Brown generating station (Units 6 and 7). Commencing in December 1999, KU and LG&E entered into a tax-efficient, 18-year lease of the CTs. KU and LG&E have provided funds to fully defease the lease, and have executed an irrevocable notice to exercise an early purchase option contained in the lease after 15.5 years. The financial statement treatment of this transaction is no different than if KU had retained its ownership. The leasing transaction was entered into following receipt of required state and federal regulatory approvals.

In case of default under the lease, KU is obligated to pay to the lessor its share of certain fees or amounts. Primary events of default include loss or destruction of the CTs, failure to insure or maintain the CTs and unwinding of the transaction due to governmental actions. No events of default currently exist with respect to the lease. Upon any termination of the lease, whether by default or expiration of its term, title to the CTs reverts jointly to KU and LG&E.

At December 31, 2007, the maximum aggregate amount of default fees or amounts was $10 million, of which KU would be responsible for 62% (approximately $6 million). KU has made arrangements with E.ON U.S., via guarantee and regulatory commitment, for E.ON U.S. to pay KU's full portion of any default fees or amounts.

Letter of Credit. KU has provided a letter of credit totaling less than $1 million to support certain obligations related to workers' compensation.

Purchased Power. KU has purchased power arrangements with OMU and OVEC. Under the OMU agreement, which could last through January 1, 2020, KU purchases all of the output of an approximately 400-Mw coal-fired generating station not required by OMU. The amount of purchased power available to KU during 2008-2010, which is expected to be approximately 6% of KU's total Kwh native load energy requirements, is dependent upon a number of factors including the OMU units' availability, maintenance schedules, fuel costs and OMU requirements. Payments are based on the total costs of the station allocated per terms of the OMU agreement. Included in the total costs is KU's proportionate share of debt service requirements on $246 million of OMU bonds outstanding at December 31, 2007. The debt service is allocated to KU based on its annual allocated share of capacity, which averaged approximately 39% in 2007. KU does not guarantee the OMU bonds, or any requirements therein, in the event of default by OMU.

KU has a contract for purchased power with OVEC, terminating in 2026, for various Mw capacities. KU has an investment of 2.5% ownership in OVEC's common stock, which is accounted for on the cost method of accounting. KU's share of OVEC's output is 2.5%, approximately 55 Mw of generation capacity. Future obligations for power purchases are shown in the following table:

(in millions)	
2008	$ 23
2009	25
2010	16
2011	8
2012	9
Thereafter	143
Total	$ 224

Construction Program. KU had approximately $392 million of commitments in connection with its construction program at December 31, 2007.

In June 2006, KU and LG&E entered into a construction contract regarding the TC2 project. The contract is generally in the form of a lump-sum, turnkey agreement for the design, engineering, procurement, construction, commissioning, testing and delivery of the project, according to designated specifications, terms and conditions. The contract price and its components are subject to a number of potential adjustments which may serve to increase or decrease the ultimate construction price paid or payable to the contractor. The contract also contains standard representations, covenants, indemnities, termination and other provisions for arrangements of this type, including termination for convenience or for cause rights.

TC2 Air Permit. The Sierra Club and other environmental groups filed a petition challenging the air permit issued for the TC2 baseload generating unit which was issued by the Kentucky Division of Air Quality in November 2005. The filing of the challenge did not stay the permit, so the Company was free to proceed with construction during the pendancy of the action. In June 2007, the state hearing officer assigned to the matter recommended upholding the air permit with minor revisions. In September 2007, the Secretary of the Kentucky Environmental and Public Protection Cabinet issued a final Order approving the hearing officer's recommendation and upholding the permit. In September 2007, KU administratively applied for a permit revision to reflect minor design changes. In October 2007, the environmental groups submitted comments objecting to the draft permit revisions and, in part, attempting to reassert general objections to the generating unit. An agency decision on the final permit revisions may occur during 2008. The Company is currently unable to determine the final outcome of this matter.

Mine Safety Compliance Costs. In March 2006, the Mine Safety and Health Administration enacted Emergency Temporary Standards regulations and has issued additional regulations as the result of the passage of the Mine Improvement and New Emergency Response Act of 2006, which was signed into law in June 2006. At the state level, Kentucky and other states that supply coal to KU, have passed new mine safety legislation. These pieces of legislation require all underground coal mines to implement new safety measures and install new safety equipment. Under the terms of some of the coal contracts KU has in place, provisions are made to allow for price adjustments for compliance costs resulting from new or amended laws or regulations. KU has begun to receive information from the mines it contracts with regarding price adjustments related to these compliance costs and has hired a consultant to review all supplier claims for validity and reasonableness. At this time KU has not been notified of claims by all mines and is reviewing those claims it has received. An adjustment will be made to the value of the coal inventory once the amount is determinable, however, the amount cannot be estimated at this time. The Company expects to recover these costs through the FAC.

Environmental Matters. KU's operations are subject to a number of environmental laws and regulations in each of the jurisdictions in which it operates, governing, among other things, air emissions, wastewater discharges, the use, handling and disposal of hazardous substances and wastes, soil and groundwater contamination and employee health and safety.

Clean Air Act Requirements. The Clean Air Act establishes a comprehensive set of programs aimed at protecting and improving air quality in the United States by, among other things, controlling stationary sources of air emissions such as power plants. While the general regulatory framework for these programs is established at the federal level, most of the programs are implemented and administered by the states under the oversight of the EPA. The key Clean Air Act programs relevant to KU's business operations are described below.

Ambient Air Quality. The Clean Air Act requires the EPA to periodically review the available scientific data for six criteria pollutants and establish concentration levels in the ambient air sufficient to protect the public health and welfare with an extra margin for safety. These concentration levels are known as national ambient air quality standards ("NAAQS"). Each state must identify "nonattainment areas" within its boundaries that fail to comply with the NAAQS and develop a SIP to bring such nonattainment areas into compliance. If a state fails to develop an adequate plan, the EPA must develop and implement a plan. As the EPA increases the stringency of the NAAQS through its periodic reviews, the attainment status of various areas may change, thereby triggering additional emission reduction obligations under revised SIPs aimed to achieve attainment.

In 1997, the EPA established new NAAQS for ozone and fine particulates that required additional reductions in SO_2 and NOx emissions from power plants. In 1998, the EPA issued its final "NOx SIP Call" rule requiring reductions in NOx emissions of approximately 85% from 1990 levels in order to mitigate ozone transport from the midwestern U.S. to the northeastern U.S. To implement the new federal requirements, Kentucky amended its SIP in 2002 to require electric generating units to reduce their NOx emissions to 0.15 pounds weight per MMBtu on a company-wide basis. In 2005, the EPA issued the CAIR which requires additional SO_2 emission reductions of 70% and NOx emission reductions of 65% from 2003 levels. The CAIR provides for a two-phase cap and trade program, with initial reductions of NOx and SO_2 emissions due by 2009 and 2010, respectively, and final reductions due by 2015. The final rule is currently under challenge in a number of federal court proceedings. In 2006, Kentucky proposed to amend its SIP to adopt state requirements similar to those under the federal CAIR. Depending on the level of action determined necessary to bring local nonattainment areas into compliance with the new ozone and fine particulate standards, KU's power plants are potentially subject to additional reductions in SO_2 and NOx emissions. KU's weighted-average company-wide emission rate for SO_2 in 2007 was approximately 1.33 lbs./MMBtu of heat input, with every generating unit below its emission limit established by the Kentucky Division for Air Quality.

Hazardous Air Pollutants. As provided in the 1990 amendments to the Clean Air Act, the EPA investigated hazardous air pollutant emissions from electric utilities and submitted a report to Congress identifying mercury emissions from coal-fired power plants as warranting further study. In 2005, the EPA issued the CAMR establishing mercury standards for new power plants and requiring all states to issue new SIPs including mercury requirements for existing power plants. The EPA issued a model rule which provides for a two-phase cap and trade program with initial reductions due by 2010 and final reductions due by 2018. The CAMR provides for reductions of 70% from 2003 levels. The EPA closely integrated the CAMR and CAIR programs to ensure that the 2010 mercury reduction targets will be achieved as a "co-benefit" of the controls installed for purposes of compliance with the CAIR. The final rule is also currently under challenge in the federal courts. In

February 2008, a federal appellate court issued a decision in one of the proceedings vacating the current CAMR, an outcome that may have the effect of resulting in more stringent mercury reduction rules. However, the ruling could be subject to further appeal. In 2006, Kentucky proposed to amend its SIP to adopt state requirements similar to those under the federal CAMR. In 2006, the Kentucky air agency adopted a regulation aimed at regulating additional hazardous air pollutants from sources including power plants, but it was withdrawn in 2007. To the extent those rules are final, they are not expected to have a material impact on KU's power plant operations.

Acid Rain Program. The 1990 amendments to the Clean Air Act imposed a two-phased cap and trade program to reduce SO_2 emissions from power plants that were thought to contribute to "acid rain" conditions in the northeastern U.S. The 1990 amendments also contained requirements for power plants to reduce NOx emissions through the use of available combustion controls.

Regional Haze. The Clean Air Act also includes visibility goals for certain federally designated areas, including national parks, and requires states to submit SIPs that will demonstrate reasonable progress toward preventing future impairment and remedying any existing impairment of visibility in those areas. In 2005, the EPA issued its Clean Air Visibility Rule detailing how the Clean Air Act's BART requirements will be applied to facilities, including power plants, built between 1962 and 1974 that emit certain levels of visibility impairing pollutants. Under the final rule, as the CAIR will result in more visibility improvement than BART, states are allowed to substitute CAIR requirements in their regional haze SIPs in lieu of controls that would otherwise be required by BART. The final rule has been challenged in the courts.

Installation of Pollution Controls. Many of the programs under the Clean Air Act utilize cap and trade mechanisms that require a company to hold sufficient emissions allowances to cover its authorized emissions on a company-wide basis and do not require installation of pollution controls on every generating unit. Under cap and trade programs, companies are free to focus their pollution control efforts on plants where such controls are particularly efficient and utilize the resulting emission allowances for smaller plants where such controls are not cost effective. KU met its Phase I SO_2 requirements primarily through installation of FGD equipment on Ghent Unit 1. KU's combined strategy for its Phase II SO_2 requirements, which commenced in 2000, includes the installation of additional FGD equipment, as well as using accumulated emissions allowances and fuel switching to defer certain additional capital expenditures. In order to achieve the NOx emission reductions and associated obligations, KU installed additional NOx controls, including SCR technology, during the 2000 to 2007 time period at a cost of $220 million. In 2001, the Kentucky Commission granted approval to recover the costs incurred by KU for these projects through the environmental surcharge mechanism. Such monthly recovery is subject to periodic review by the Kentucky Commission.

In order to achieve the emissions reductions mandated by the CAIR and CAMR, KU expects to incur additional capital expenditures totaling approximately $675 million during the 2008 through 2010 time period for pollution controls including FGD and SCR equipment, and additional operating and maintenance costs in operating such controls. In 2005, the Kentucky Commission granted approval to recover the costs incurred by KU for these projects through the ECR mechanism. Such monthly recovery is subject to periodic review by the Kentucky Commission. KU believes its costs in reducing SO_2, NOx and mercury emissions to be comparable to those of similarly situated utilities with like generation assets. KU's compliance plans are subject to many factors including developments in the emission allowance and fuels markets, future legislative and regulatory enactments, legal proceedings and advances in clean air technology. KU will continue to monitor these developments to ensure that its environmental obligations are met in the most efficient and cost-effective manner.

Potential GHG Controls. In 2005, the Kyoto Protocol for reducing GHG emissions took effect, obligating 37 industrialized countries to undertake substantial reductions in GHG emissions. The U.S. has not ratified the Kyoto Protocol and there are currently no mandatory GHG emission reduction requirements at the federal level. Legislation mandating GHG reductions has been introduced in the Congress, but no federal legislation has been enacted to date. In the absence of a program at the federal level, various states have adopted their own GHG emission reduction programs. Such programs have been adopted in various states including 11 northeastern U.S. states and the District of Columbia under the Regional GHG Initiative program and California. Substantial efforts to pass federal GHG legislation are ongoing. In addition, litigation is currently pending before various courts to determine whether the EPA and the states have the authority to regulate GHG emissions under existing law. In April 2007, the U.S. Supreme Court ruled that the EPA has the authority to regulate GHG under the Clean Air Act. KU is monitoring ongoing efforts to enact GHG reduction requirements at the state and federal level and is assessing potential impacts of such programs and strategies to mitigate those impacts. KU is unable to predict whether mandatory GHG reduction requirements will ultimately be enacted. As a Company with significant coal-fired generating assets, KU could be substantially impacted by programs requiring mandatory reductions in GHG emissions, although the precise impact on the operations of KU, including the reduction targets and deadlines that would be applicable, cannot be determined prior to the enactment of such programs.

Brown New Source Review Litigation. In April 2006, the EPA issued an NOV alleging that KU had violated certain provisions of the Clean Air Act's new source review rules relating to work performed in 1997, on a boiler and turbine at KU's E.W. Brown generating station. In December 2006, the EPA issued a second NOV alleging the Company had exceeded heat input values in violation of the air permit for the unit. During 2006, KU provided data responses to the EPA with respect to the allegations in the NOVs. In March 2007, the Department of Justice filed a complaint in federal court in Kentucky alleging the same violations specified in the prior NOVs. The complaint seeks civil penalties, including potential per-day fines, remedial measures and injunctive relief. In April 2007, KU filed an answer in the civil suit denying the allegations. In July 2007, a July 2009 date for trial on the merits was scheduled. The parties continue periodic settlement discussions and a $2 million accrual has been recorded based on the current status of those discussions, however, KU cannot determine the overall outcome or potential effects of these matters, including whether substantial fines, penalties or remedial construction may result.

Section 114 Requests. In August 2007, the EPA issued administrative information requests under Section 114 of the Clean Air Act requesting new source review-related data regarding certain construction and maintenance activities at LG&E's Mill Creek 4 and Trimble County 1 generating units and KU's Ghent 2 generating unit. The Companies are complying with the information requests and are not able to predict further proceedings in this matter at this time.

Ghent Opacity NOV. In September 2007, the EPA issued an NOV alleging that KU had violated certain provisions of the Clean Air Act's operating rules relating to opacity during June and July of 2007 at Units 1 and 3 of KU's Ghent generating station. The parties have commenced initial discussions on this matter. KU is not able to estimate the outcome or potential effects of these matters, including whether substantial fines, penalties or remedial construction may result.

General Environmental Proceedings. KU has recently settled certain environmental matters. During 2005 and 2006, final judicial and administrative approvals were received regarding a consent decree relating to the October 1999 leak of approximately 38,000 gallons of diesel fuel (of which 34,000 gallons were recovered) from an underground pipeline at KU's E.W. Brown Station. Under the terms of the settlement, KU paid a civil penalty in 2006 and has agreed to construct a supplemental environmental project and maintain the project for ten years, each at a cost of less than $1 million. During 2006, final judicial and administrative approvals were received regarding a settlement associated with a former transformer scrap-yard which had been the subject of

April 2002 correspondence to KU and other potentially responsible parties. Under the terms of the settlement, the parties bore aggregate cleanup costs of approximately $2 million, of which KU's share was less than $1 million, which was paid in December 2006.

From time to time, KU appears before the EPA, various state or local regulatory agencies and state and federal courts regarding matters involving compliance with applicable environmental laws and regulations. Such matters include liability under the Comprehensive Environmental Response, Compensation and Liability Act for cleanup at various off-site waste sites and ongoing claims regarding GHG emissions from KU's generating stations. Based on analysis to date, the resolution of such matters is not expected to have a material impact on the operations of KU.

Note 10 - Jointly Owned Electric Utility Plant

KU and LG&E have begun construction of TC2, a jointly owned unit at the Trimble County site. KU and LG&E own undivided 60.75% and 14.25% interests, respectively, in TC2. Of the remaining 25% of TC2, Illinois Municipal Electric Agency ("IMEA") owns a 12.12% undivided interest and Indiana Municipal Power Agency ("IMPA") owns a 12.88% undivided interest. Each company is responsible for its proportionate share of capital cost during construction, and fuel, operation and maintenance cost when TC2 begins operation, which is expected to occur in 2010.

	TC2				
	LG&E	KU	IMPA	IMEA	Total
Ownership interest	14.25%	60.75%	12.88%	12.12%	100%
Mw capacity	107	455	97	91	750

(in millions)	LG&E	KU
Construction work in progress	$74	$332

KU and LG&E jointly own the following CTs and related equipment:

($ in millions)	KU				LG&E				Total			
Ownership Percentage	Mw Capacity	($) Cost	($) Depre-ciation	($) Net Book Value	Mw Capacity	($) Cost	($) Depre-ciation	($) Net Book Value	Mw Capacity	($) Cost	($) Depre-ciation	($) Net Book Value
KU 47%, LG&E 53% (1)	129	51	(11)	40	146	58	(12)	46	275	109	(23)	86
KU 62%, LG&E 38% (2)	190	78	(14)	64	118	50	(10)	40	308	128	(24)	104
KU 71%, LG&E 29% (3)	228	80	(14)	66	92	32	(6)	26	320	112	(20)	92
KU 63%, LG&E 37% (4)	404	137	(17)	120	236	79	(8)	71	640	216	(25)	191
KU 71%, LG&E 29% (5)	n/a	9	(2)	7	n/a	3	-	3	n/a	12	(2)	10

1) Comprised of Paddy's Run 13 and E.W. Brown 5. In addition to the above jointly owned utility plant, there is an inlet air cooling system attributable to Unit 5 and units 8-11 at the E.W. Brown facility. This inlet air cooling system is not jointly owned, however, it is used to increase production on the units to which it relates, resulting in an additional 88 Mw of capacity for KU.
2) Comprised of units 6 and 7 at the E.W. Brown facility.
3) Comprised of units 5 and 6 at the Trimble County facility.
4) Comprised of CT Substation 7-10 and units 7, 8, 9 and 10 at the Trimble County facility.
5) Comprised of CT Substation 5 and 6 and CT Pipeline at the Trimble County facility.

Both KU's and LG&E's participating share of direct expenses of the jointly owned plants is included in the corresponding operating expenses on its respective income statement (e.g., fuel, maintenance of plant, other operating expense).

Note 11 - Related Party Transactions

KU, subsidiaries of E.ON U.S. and subsidiaries of E.ON engage in related party transactions. Transactions between KU and E.ON U.S. subsidiaries are eliminated upon consolidation of E.ON U.S. Transactions between KU and E.ON subsidiaries are eliminated upon consolidation of E.ON. These transactions are generally performed at cost and are in accordance with the FERC regulations under PUHCA 2005 and the applicable Kentucky Commission and Virginia Commission regulations. The significant related party transactions are disclosed below.

Electric Purchases

KU and LG&E purchase energy from each other in order to effectively manage the load of their retail and wholesale customers. These sales and purchases are included in the statements of income as operating revenues and purchased power operating expense. KU intercompany electric revenues and purchased power expense for the years ended December 31, were as follows:

(in millions)	2007	2006
Electric operating revenues from LG&E	$46	$77
Purchased power from LG&E	93	99

Interest Charges

See Note 8, Notes Payable and Other Short-Term Obligations, for details of intercompany borrowing arrangements. Intercompany agreements do not require interest payments for receivables related to services provided when settled within 30 days.

KU's intercompany interest income and expense for the years ended December 31, were as follows:

(in millions)	2007	2006
Interest on money pool loans	$ 6	$ 3
Interest on Fidelia loans	35	21

Other Intercompany Billings

E.ON U.S. Services provides KU with a variety of centralized administrative, management and support services. These charges include payroll taxes paid by E.ON U.S. on behalf of KU, labor and burdens of E.ON U.S. Services employees performing services for KU and vouchers paid by E.ON U.S. Services on behalf of KU. The cost of these services is directly charged to KU, or for general costs which cannot be directly attributed, charged based on predetermined allocation factors, including the following ratios: number of customers, total assets, revenues, number of employees and other statistical information. These costs are charged on an actual cost basis.

In addition, KU and LG&E provide services to each other and to E.ON U.S. Services. Billings between KU and LG&E relate to labor and overheads associated with union employees performing work for the other utility, charges related to jointly owned CTs and other miscellaneous charges. Billings from KU to E.ON U.S. Services relate to cash received by E.ON U.S. Services on behalf of KU, primarily tax settlements, and other payments made by KU on behalf of other non-regulated businesses which are paid through E.ON U.S. Services.

Intercompany billings to and from KU for the years ended December 31, were as follows:

(in millions)	2007	2006
E.ON U.S. Services billings to KU	$488	$353
KU billings to LG&E	6	56
LG&E billings to KU	12	53
KU billings to E.ON U.S. Services	26	23

In September and December 2007, KU received capital contributions from its shareholder, E.ON U.S. in the amount of $55 million and $20 million, respectively.

Note 12 – Accumulated Other Comprehensive Income

Accumulated other comprehensive income (loss) consisted of the following:

(in millions)	Minimum Pension Liability Adjustment	Pre-Tax	Income Taxes	Net
Balance at December 31, 2005	$ (32)	$ (32)	$ 13	$(19)
Minimum pension liability adjustment	32	32	(13)	(19)
Balance at December 31, 2006	$ -	$ -	$ -	$ -
Balance at December 31, 2007	$ -	$ -	$ -	$ -

Subsequent to the application of SFAS No. 158, adjustments to the minimum pension liability are recorded as regulatory assets and liabilities. As a result, there are no adjustments to the minimum pension liability recorded in accumulated other comprehensive income at December 31, 2007 or 2006.

Note 13 – Subsequent Events

On January 18, 2008, the Kentucky Commission issued an Order approving the charges and credits billed through the FAC during the review period of November 1, 2006 through April 30, 2007.

On January 31, 2008 and February 14, 2008, the ratings of the Carroll County 2004 Series A bonds were downgraded from AAA to AA by S&P and from Aaa to A2 by Moody's, respectively, due to downgrades of the bond insurer. On February 25, 2008, the bonds were subsequently downgraded from AA to A by S&P, due to a further downgrade of the insurer.

On February 1, 2008, the Kentucky Commission issued an Order approving the real-time pricing pilot program proposed by KU, for implementation within approximately eight months, for its large commercial and industrial customers.

On February 7, 2008 and February 25, 2008, the Carroll County 2006 Series C bonds were downgraded from Aaa to A2 by Moody's and from AAA to A- by S&P, due to downgrades of the bond insurer.

On February 26, 2008, KU commenced steps, including notice to relevant parties, to convert the Carroll County 2007 Series A bonds and the Trimble County 2007 Series A bonds, from the auction rate mode to a fixed interest rate mode. Such conversions are scheduled to occur on April 4, 2008.

Beginning in late 2007, the interest rates on the insured bonds, wherein interest rates are reset either weekly or every 35 days via an auction process, began to increase due to investor concerns about the creditworthiness of the bond insurers. In 2008, interest rates have continued to increase, and the Company has experienced "failed auctions" when there are insufficient bids for the bonds. When there is a failed auction, the interest rate is set pursuant to a formula stipulated in the indenture which can be as high as 15%. During 2007, the average rate on the auction rate bonds was 3.96%, whereas the average rate in January and February of 2008 was 4.72%.

On March 4, 2008, the FERC issued an Order approving the MISO exit fee recalculation agreement which provides KU with an immediate recovery of $1 million and an estimated $3 million over the next eight years for credits realized from other payments the MISO will receive, plus interest.

On March 17, 2008, KU commenced steps, including notice to relevant parties, to convert the Carroll County 2006 Series C bonds from the auction rate mode to a weekly interest rate mode. Such conversion is scheduled to occur on April 16, 2008.

Report of Independent Auditors

To the Shareholder of Kentucky Utilities Company:

In our opinion, the accompanying balance sheets and the related statements of capitalization, income, retained earnings, cash flows and comprehensive income present fairly, in all material respects, the financial position of Kentucky Utilities Company at December 31, 2007 and 2006, and the results of its operations and its cash flows for the years then ended in conformity with accounting principles generally accepted in the United States of America. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits. We conducted our audits of these statements in accordance with auditing standards generally accepted in the United States of America. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

As discussed in Note 2 to the financial statements, Kentucky Utilities Company changed the manner in which it accounts for defined benefit pension and other postretirement benefit plans as of December 31, 2006.

/s/ PricewaterhouseCoopers LLP
Louisville, Kentucky
March 18, 2008

APPENDIX B

Opinions of Bond Counsel and
Forms of Conversion Opinions of Bond Counsel

APPENDIX B-1

Opinion of Bond Counsel dated February 23, 2007 relating to the 2006 Series B Bonds

STOLL·KEENON·OGDEN
PLLC

2000 PNC PLAZA
500 WEST JEFFERSON STREET
LOUISVILLE, KENTUCKY 40202-2828
502-333-6000
FAX: 502-333-6099
WWW.SKOFIRM.COM

February 23, 2007

Re: $54,000,000 County of Carroll, Kentucky, Environmental Facilities Revenue Refunding Bonds, 2006 Series B (Kentucky Utilities Company Project)

We hereby certify that we have examined certified copies of the proceedings of record of the County of Carroll, Kentucky (the "County"), acting by and through its Fiscal Court as its duly authorized governing body, preliminary to and in connection with the issuance by the County of its Environmental Facilities Revenue Refunding Bonds, 2006 Series B (Kentucky Utilities Company Project), dated their date of issuance, in the aggregate principal amount of $54,000,000 (the "Bonds"). The Bonds are issued under the provisions of Sections 103.200 to 103.285, inclusive, of the Kentucky Revised Statutes (the "Act"), for the purpose of providing funds which will be used, with other funds provided by Kentucky Utilities Company (the "Company") for the current refunding of $54,000,000 aggregate principal amount of the County's Collateralized Solid Waste Disposal Facilities Revenue Bonds (Kentucky Utilities Company Project) 1994 Series A, dated November 23, 1994 (the "Prior Bonds"), which were issued for the purpose of financing a portion of the costs of construction, acquisition, installation and equipping of certain solid waste disposal facilities to serve the Ghent Generating Station of the Company in Carroll County, Kentucky (the "Project") in order to provide for the collection, storage, treatment, processing and final disposal of solid wastes, as provided by the Act.

The Bonds mature on October 1, 2034 and bear interest initially at the Dutch Auction Rate, as defined in the Indenture, hereinafter described, subject to change as provided in such Indenture. The Bonds will be subject to optional and mandatory redemption prior to maturity at the times, in the manner and upon the terms set forth in the Bonds. From such examination of the proceedings of the Fiscal Court of the County referred to above and from an examination of the Act, we are of the opinion that the County is duly authorized and empowered to issue the Bonds under the laws of the Commonwealth of Kentucky now in force.

We have examined an executed counterpart of a certain Loan Agreement, dated as of October 1, 2006 (the "Loan Agreement"), between the County and the Company and a certified copy of the proceedings of record of the Fiscal Court of the County preliminary to and in connection with the execution and delivery of the Loan Agreement, pursuant to which the County has agreed to issue the Bonds and to lend the proceeds thereof to the Company to provide funds to pay and discharge, with other funds provided by the Company, the Prior Bonds.

The Company has agreed to make Loan payments to the Trustee at times and in amounts fully adequate to pay maturing principal of, interest on and redemption premium, if any, on the Bonds as same become due and payable. From such examination, we are of the opinion that such proceedings of the Fiscal Court of the County show lawful authority for the execution and delivery of the Loan Agreement; that the Loan Agreement has been duly authorized, executed and delivered by the County; and that the Loan Agreement is a legal, valid and binding obligation of the County, enforceable in accordance with its terms, subject to the qualification that the enforcement thereof may be limited by laws relating to bankruptcy, insolvency or other similar laws affecting creditors' rights generally, including equitable provisions where equitable remedies are sought.

We have also examined an executed counterpart of a certain Indenture of Trust, dated as of October 1, 2006 (the "Indenture"), by and between the County and Deutsche Bank Trust Company Americas, as trustee (the "Trustee"), securing the Bonds and setting forth the covenants and undertakings of the County in connection with the Bonds and a certified copy of the proceedings of record of the Fiscal Court of the County preliminary to and in connection with the execution and delivery of the Indenture. Pursuant to the Indenture, certain of the County's rights under the Loan Agreement, including the right to receive payments thereunder, and all moneys and securities held by the Trustee in accordance with the Indenture (except moneys and securities in the Rebate Fund created thereby) have been assigned to the Trustee, as security for the holders of the Bonds. From such examination, we are of the opinion that such proceedings of the Fiscal Court of the County show lawful authority for the execution and delivery of the Indenture; that the Indenture has been duly authorized, executed and delivered by the County; and that the Indenture is a legal, valid and binding obligation upon the parties thereto according to its terms, subject to the qualification that the enforcement thereof may be limited by laws relating to bankruptcy, insolvency or other similar laws affecting creditors' rights generally, including equitable provisions where equitable remedies are sought.

In our opinion the Bonds have been validly authorized, executed and issued in accordance with the laws of the Commonwealth of Kentucky now in full force and effect, and constitute legal, valid and binding special obligations of the County entitled to the benefit of the security provided by the Indenture and enforceable in accordance with their terms, subject to the qualification that the enforcement thereof may be limited by laws relating to bankruptcy, insolvency or other similar laws affecting creditors' rights generally, including equitable provisions where equitable remedies are sought. The Bonds are payable by the County solely and only from payments and other amounts derived from the Loan Agreement and as provided in the Indenture.

In our opinion, under existing laws, including current statutes, regulations, administrative rulings and official interpretations by the Internal Revenue Service, subject to the exceptions and qualifications contained in the succeeding paragraphs, interest on the Bonds is excluded from the gross income of the recipients thereof for federal income tax purposes, except that no opinion is expressed regarding such exclusion from gross income with respect to any Bond during any period in which it is held by a "substantial user" of the Project or a "related person," as such terms are used in Section 147(a) of the Internal Revenue Code of 1986, as amended (the "Code"). Interest on the Bonds is a separate item of tax preference in determining alternative minimum taxable income for individuals and corporations under the Code. In arriving at this opinion, we have relied upon representations, factual statements and certifications of the Company with respect to certain material facts which are solely within the Company's knowledge in reaching our conclusion, inter alia, that not less than 95% of the net proceeds of the Prior Bonds were used to finance solid waste disposal facilities qualified for financing under Section 142(a)(6) of the Code and the Act. Further, in arriving at the opinion set forth in this paragraph as to the exclusion from gross income of interest on the Bonds, we have assumed and this opinion is conditioned on, the accuracy of and continuing compliance by the Company and the County with representations and covenants set forth in the Loan Agreement and the Indenture which are intended to assure compliance with certain tax-exempt interest provisions of the Code. Such representations and covenants must be accurate and must be complied with subsequent to the issuance of the Bonds in order that interest on the Bonds be excluded from gross income for federal income tax purposes. Failure to comply with certain of such representations and covenants in respect of the Bonds subsequent to the issuance of the Bonds could cause the interest thereon to be included in gross income for federal income tax purposes retroactively to the date of issuance of the Bonds. We express no opinion (i) regarding the exclusion of interest on any Bond from gross income for federal income tax purposes on or after the date on which any change, including any interest rate conversion, permitted by the documents (other than with approval of this firm) is taken which adversely affects the tax treatment of the Bonds or (ii) as to the treatment for purposes of federal income taxation of interest on the Bonds upon a Determination of Taxability. We are further of the opinion that interest on the Bonds is excluded from gross income of the recipients thereof for Kentucky income tax purposes and that the Bonds are exempt from ad valorem taxation by the Commonwealth of Kentucky and all political subdivisions thereof.

Our opinion as to the exclusion of interest on the Bonds from gross income for federal income tax purposes and federal tax treatment of interest on the Bonds is further subject to the following exceptions and qualifications:

(a) The Code provides for a "branch profits tax" which subjects to tax, at a rate of 30%, the effectively connected earnings and profits of a foreign corporation which engages in a United States trade or business. Interest on the Bonds would be includable in the amount of effectively connected earnings and profits and thus would increase the branch profits tax liability.

(b) The Code also provides that passive investment income, including interest on the Bonds, may be subject to taxation for any S corporation with Subchapter C earnings and profits at the close of its taxable year if greater than 25% of its gross receipts is passive investment income.

Except as stated above, we express no opinion as to any federal or Kentucky tax consequences resulting from the receipt of interest on the Bonds.

Holders of the Bonds should be aware that the ownership of the Bonds may result in collateral federal income tax consequences. For instance, the Code provides that, for taxable years beginning after December 31, 1986, property and casualty insurance companies will be required to reduce their loss reserve deductions by 15% of the tax-exempt interest received on certain obligations, such as the Bonds, acquired after August 7, 1986. (For purposes of the immediately preceding sentence, a portion of dividends paid to an affiliated insurance company may be treated as tax-exempt interest.) The Code further provides for the disallowance of any deduction for interest expenses incurred by banks and certain other financial institutions allocable to carrying certain tax-exempt obligations, such as the Bonds, acquired after August 7, 1986. The Code also provides that, with respect to taxpayers other than such financial institutions, such taxpayers will be unable to deduct any portion of the interest expenses incurred or continued to purchase or carry the Bonds. The Code also provides, with respect to individuals, that interest on tax-exempt obligations, including the Bonds, is included in modified adjusted gross income for purposes of determining the taxability of social security and railroad retirement benefits. Furthermore, the earned income credit is not allowed for individuals with an aggregate amount of disqualified income within the meaning of section 32 of the Code, which exceeds $2,200. Interest on the Bonds will be taken into account in the calculation of disqualified income.

We have received opinions of John R. McCall, Esq., General Counsel of the Company and Jones Day, Chicago, Illinois, counsel to the Company, of even date herewith. In rendering this opinion, we have relied upon said opinions with respect to the matters therein. We have also received an opinion of even date herewith of Hon. James C. Monk, County Attorney of the County and relied upon said opinion with respect to the matters therein. Said opinions are in forms satisfactory to us as to both scope and content.

We express no opinion as to the title to, the description of, or the existence or priority of any liens, charges or encumbrances on, the Project.

In rendering the foregoing opinions, we are passing upon only those matters specifically set forth in such opinions and are not passing upon the investment quality of the Bonds or the accuracy or completeness of any statements made in connection with any offer or sale thereof. The opinions herein are expressed as of the date hereof and we assume no obligation to supplement or update such opinions to reflect any facts or circumstances that may hereafter come to our attention or any changes in law that may hereafter occur.

We are members of the Bar of the Commonwealth of Kentucky and do not purport to be experts on the laws of any jurisdiction other than the Commonwealth of Kentucky and the United States of America, and we express no opinion as to the laws of any jurisdiction other than those specified.

Respectfully submitted,

Stoll Keenon Ogden PLLC

STOLL KEENON OGDEN PLLC

APPENDIX B-2

Opinion of Bond Counsel dated October 17, 2008 relating to the 2008 Series A Bonds

STOLL·KEENON·OGDEN
PLLC

2000 PNC PLAZA
500 WEST JEFFERSON STREET
LOUISVILLE, KENTUCKY 40202-2828
502-333-6000
FAX: 502-333-6099
WWW.SKOFIRM.COM

October 17, 2008

Re: $77,947,405 "County of Carroll, Kentucky, Environmental Facilities Revenue Bonds, 2008 Series A (Kentucky Utilities Company Project)"

We hereby certify that we have examined certified copies of the proceedings of record of the County of Carroll, Kentucky (the "County"), acting by and through its Fiscal Court as its duly authorized governing body, preliminary to and in connection with the issuance by the County of its Environmental Facilities Revenue Bonds, 2008 Series A (Kentucky Utilities Company Project), dated their date of issuance, in the aggregate principal amount of $77,947,405 (the "Bonds"). The Bonds are issued under the provisions of Sections 103.200 to 103.285, inclusive, of the Kentucky Revised Statutes (the "Act"), for the purpose of providing funds which will be used, with other funds provided by Kentucky Utilities Company (the "Company") for the purposes of (i) financing a portion of the costs of construction, acquisition, installation and equipping of certain solid waste disposal facilities to serve the Ghent Generating Station of the Company in Carroll County, Kentucky (the "Construction Project") in order to provide for the collection, storage, treatment and final disposal of solid wastes, as provided by the Act in the principal amount of $18,026,265, and (ii) currently refunding (a) $13,266,950 outstanding principal amount of County of Carroll, Kentucky, Environmental Facilities Revenue Bonds, 2005 Series A (Kentucky Utilities Company Project) (the "2005 Series A Bonds"), (b) $13,266,950 outstanding principal amount of County of Carroll, Kentucky, Environmental Facilities Revenue Bonds, 2005 Series B (Kentucky Utilities Company Project) (the "2005 Series B Bonds"), (c) $16,693,620 outstanding principal amount of County of Carroll, Kentucky, Environmental Facilities Revenue Bonds, 2006 Series A (Kentucky Utilities Company Project) (the "2006 Series A Bonds") and (d) $16,693,620 outstanding principal amount of County of Carroll, Kentucky, Environmental Facilities Revenue Bonds, 2006 Series C (Kentucky Utilities Company Project) (the "2006 Series C Bonds" and, together with the 2005 Series A Bonds, the 2005 Series B Bonds and the 2006 Series A Bonds, the "Refunded Bonds"), which were issued for the purpose of financing all or a portion of the qualified costs of acquisition, construction, installation and equipping of certain solid waste disposal facilities to serve the Ghent Generating Station of Company in Carroll County, Kentucky (the "Refunding Project" and, together with the Construction Project, the "Project"), as provided by the Act.

The Bonds mature on February 1, 2032, and bear interest initially at the Flexible Rate, as defined in the Indenture, hereinafter described, subject to change as provided in such Indenture. The Bonds will be subject to optional and mandatory redemption prior to maturity at the times, in the manner and upon the terms set forth in the Bonds. From such examination of the proceedings of the Fiscal Court of the County referred to above and from an examination of the Act, we are of the opinion that the County is duly authorized and empowered to issue the Bonds under the laws of the Commonwealth of Kentucky now in force.

We have examined an executed counterpart of a certain Loan Agreement, dated as of August 1, 2008 (the "Loan Agreement"), between the County and the Company and a certified copy of the proceedings of record of the Fiscal Court of the County preliminary to and in connection with the execution and delivery of the Loan Agreement, pursuant to which the County has agreed to issue the Bonds and to lend the proceeds thereof to the Company to provide funds to finance a portion of the costs of the acquisition, construction, installation and equipping of the Construction Project and to pay and discharge with other funds provided by the Company, the Refunded Bonds. The Company has agreed to make Loan payments to the Trustee at times and in amounts fully adequate to pay maturing principal of, interest on and redemption premium, if any, on the Bonds as same become due and payable. From such examination, we are of the opinion that such proceedings of the Fiscal Court of the County show lawful authority for the execution and delivery of the Loan Agreement; that the Loan Agreement has been duly authorized, executed and delivered by the County; and that the Loan Agreement is a legal, valid and binding obligation of the County, enforceable in accordance with its terms, subject to the qualification that the enforcement thereof may be limited by laws relating to bankruptcy, insolvency or other similar laws affecting creditors' rights generally, including equitable provisions where equitable remedies are sought.

We have also examined an executed counterpart of a certain Indenture of Trust, dated as of August 1, 2008 (the "Indenture"), by and between the County and Deutsche Bank Trust Company Americas, as trustee (the "Trustee"), securing the Bonds and setting forth the covenants and undertakings of the County in connection with the Bonds and a certified copy of the proceedings of record of the Fiscal Court of the County preliminary to and in connection with the execution and delivery of the Indenture. Pursuant to the Indenture, certain of the County's rights under the Loan Agreement, including the right to receive payments thereunder, and all moneys and securities held by the Trustee in accordance with the Indenture (except moneys and securities in the Rebate Fund created thereby) have been assigned to the Trustee, as security for the holders of the Bonds. From such examination, we are of the opinion that such proceedings of the Fiscal Court of the County show lawful authority for the execution and delivery of the Indenture; that the Indenture has been duly authorized, executed and delivered by the County; and that the Indenture is a legal, valid and binding obligation upon the parties thereto according to its terms, subject to the qualification that the enforcement thereof may be limited by laws relating to bankruptcy, insolvency or other similar laws affecting creditors' rights generally, including equitable provisions where equitable remedies are sought.

In our opinion the Bonds have been validly authorized, executed and issued in accordance with the laws of the Commonwealth of Kentucky now in full force and effect, and constitute legal, valid and binding special obligations of the County entitled to the benefit of the security provided by the Indenture and enforceable in accordance with their terms, subject to the qualification that the enforcement thereof may be limited by laws relating to bankruptcy, insolvency or other similar laws affecting creditors' rights generally, including equitable provisions where equitable remedies are sought. The Bonds are payable by the County solely and only from payments and other amounts derived from the Loan Agreement and as provided in the Indenture.

In our opinion, under existing laws, including current statutes, regulations, administrative rulings and official interpretations by the Internal Revenue Service, subject to the exceptions and qualifications contained in the succeeding paragraphs, (i) interest on the Bonds is excluded from the gross income of the recipients thereof for federal income tax purposes, except that no opinion is expressed regarding such exclusion from gross income with respect to any Bond during any period in which it is held by a "substantial user" of the Project or a "related person," as such terms are used in Section 147(a) of the Internal Revenue Code of 1986, as amended (the "Code") and (ii) interest on the Bonds is a separate item of tax preference in determining alternative minimum taxable income for individuals and corporations under the Code. In arriving at this opinion, we have relied upon representations, factual statements and certifications of the Company with respect to certain material facts which are solely within the Company's knowledge in reaching our conclusion, inter alia, that not less than 95% of the proceeds of the Bonds will be used to finance or refinance solid waste disposal facilities qualified for financing under Section 142(a)(6) of the Code and the Act. Further, in arriving at the opinion set forth in this paragraph as to the exclusion from gross income of interest on the Bonds, we have assumed and this opinion is conditioned on, the accuracy of and continuing compliance by the Company and the County with representations and covenants set forth in the Loan Agreement and the Indenture which are intended to assure compliance with certain tax-exempt interest provisions of the Code. Such representations and covenants must be accurate and must be complied with subsequent to the issuance of the Bonds in order that interest on the Bonds be excluded from gross income for federal income tax purposes. Failure to comply with certain of such representations and covenants in respect of the Bonds subsequent to the issuance of the Bonds could cause the interest thereon to be included in gross income for federal income tax purposes retroactively to the date of issuance of the Bonds. We express no opinion (i) regarding the exclusion of interest on any Bond from gross income for federal income tax purposes on or after the date on which any change, including any interest rate conversion, permitted by the documents (other than with approval of this firm) is taken which adversely affects the tax treatment of the Bonds or (ii) as to the treatment for purposes of federal income taxation of interest on the Bonds upon a Determination of Taxability. We are further of the opinion that interest on the Bonds is excluded from gross income of the recipients thereof for Kentucky income tax purposes and that the Bonds are exempt from ad valorem taxation by the Commonwealth of Kentucky and all political subdivisions thereof.

Our opinion as to the exclusion of interest on the Bonds from gross income for federal income tax purposes and federal tax treatment of interest on the Bonds is further subject to the following exceptions and qualifications:

(a) The Code provides for a "branch profits tax" which subjects to tax, at a rate of 30%, the effectively connected earnings and profits of a foreign corporation which engages in a United States trade or business. Interest on the Bonds would be includable in the amount of effectively connected earnings and profits and thus would increase the branch profits tax liability.

(b) The Code also provides that passive investment income, including interest on the Bonds, may be subject to taxation for any S corporation with Subchapter C earnings and profits at the close of its taxable year if greater than 25% of its gross receipts is passive investment income.

Except as stated above, we express no opinion as to any federal or Kentucky tax consequences resulting from the receipt of interest on the Bonds.

Holders of the Bonds should be aware that the ownership of the Bonds may result in collateral federal income tax consequences. For instance, the Code provides that, for taxable years beginning after December 31, 1986, property and casualty insurance companies will be required to reduce their loss reserve deductions by 15% of the tax-exempt interest received on certain obligations, such as the Bonds, acquired after August 7, 1986. (For purposes of the immediately preceding sentence, a portion of dividends paid to an affiliated insurance company may be treated as tax-exempt interest.) The Code further provides for the disallowance of any deduction for interest expenses incurred by banks and certain other financial institutions allocable to carrying certain tax-exempt obligations, such as the Bonds, acquired after August 7, 1986. The Code also provides that, with respect to taxpayers other than such financial institutions, such taxpayers will be unable to deduct any portion of the interest expenses incurred or continued to purchase or carry the Bonds. The Code also provides, with respect to individuals, that interest on tax-exempt obligations, including the Bonds, is included in modified adjusted gross income for purposes of determining the taxability of social security and railroad retirement benefits. Furthermore, the earned income credit is not allowed for individuals with an aggregate amount of disqualified income within the meaning of Section 32 of the Code, which exceeds $2,200. Interest on the Bonds will be taken into account in the calculation of disqualified income.

We have received opinions of John R. McCall, Esq., General Counsel of the Company, and Jones Day, Chicago, Illinois, counsel to the Company, of even date herewith. In rendering this opinion, we have relied upon said opinions with respect to the matters therein. We have also received an opinion of even date herewith of Hon. James C. Monk, County Attorney of the County and relied upon said opinion with respect to the matters therein. Said opinions are in forms satisfactory to us as to both scope and content.

We express no opinion as to the title to, the description of, or the existence or priority of any liens, charges or encumbrances on, the Project.

In rendering the foregoing opinions, we are passing upon only those matters specifically set forth in such opinions and are not passing upon the investment quality of the Bonds or the accuracy or completeness of any statements made in connection with any offer or sale thereof. The opinions herein are expressed as of the date hereof and we assume no obligation to supplement or update such opinions to reflect any facts or circumstances that may hereafter come to our attention or any changes in law that may hereafter occur.

We are members of the Bar of the Commonwealth of Kentucky and do not purport to be experts on the laws of any jurisdiction other than the Commonwealth of Kentucky and the United States of America, and we express no opinion as to the laws of any jurisdiction other than those specified.

Respectfully submitted,

Stoll Keenon Ogden PLLC

STOLL KEENON OGDEN PLLC

APPENDIX B-3

(Form of Conversion Opinion of Bond Counsel)
(2006 Series B Bonds)

December 19, 2008

County of Carroll, Kentucky
Carrollton, Kentucky 41008

Deutsche Bank Trust Company Americas,
as Trustee
Summit, New Jersey 07901

Re: Conversion to Weekly Rate Period of $54,000,000 "County of Carroll, Kentucky, Environmental Facilities Revenue Refunding Bonds, 2006 Series B (Kentucky Utilities Company Project)"

Ladies and Gentlemen:

This opinion is being furnished in accordance with the requirements of the Indenture of Trust, dated as of October 1, 2006 (the "Indenture"), between the County of Carroll, Kentucky (the "Issuer") and Deutsche Bank Trust Company Americas, as Trustee (the "Trustee"), pertaining to $54,000,000 principal amount of County of Carroll, Kentucky, Environmental Facilities Revenue Refunding Bonds, 2006 Series B (Kentucky Utilities Company Project), dated February 23, 2007 (the "Bonds"), in order to satisfy certain requirements of Section 2.02(e)(i) of the Indenture. Pursuant to Section 2.02(e)(i) of the Indenture, the interest rate on the Bonds is being converted from a Dutch Auction Rate to a Weekly Rate effective on December 19, 2008, the Conversion Date. The terms used herein denoted by initial capitals and not otherwise defined shall have the meanings specified in the Indenture.

We have examined the law and such documents and matters as we have deemed necessary to provide this opinion. As to questions of fact material to the opinions expressed herein, we have relied upon the provisions of the Indenture and related documents, and upon representations made to us without undertaking to verify the same by independent investigation.

Based upon the foregoing, as of the date hereof, we are of the opinion that the conversion of the interest rate on the Bonds as described herein (a) is authorized or permitted by the Act and the Indenture and (b) will not adversely affect the validity of the Bonds or any exclusion from gross income for federal income tax purposes to which interest on the Bonds would otherwise be entitled. Interest on the Bonds is not and will not be excluded from gross income during any period when the Bonds are held by the Company or a "related person" of the Company as defined in Section 147(a) of the Internal Revenue Code of 1986, as amended.

In rendering this opinion, we assume, without verifying, that the Issuer and the Company have complied and will comply with all covenants contained in the Indenture, the Loan Agreement between the Issuer and the Company, dated October 1, 2006, and other documents relating to the Bonds. We rendered our approving opinion at the time of the issuance of the

Bonds relating to, among other things, the validity of the Bonds and the exclusion from federal income taxation of interest on the Bonds. We have not been requested to update or continue such opinion and have not undertaken to do so. Accordingly, we do not express any opinion with respect to the Bonds except as set forth above.

Our opinion represents our legal judgment based upon our review of the law and the facts that we deem relevant to render such opinion and is not a guarantee of a result. This opinion is given as of the date hereof and we assume no obligation to review or supplement this opinion to reflect any facts or circumstances that may hereafter come to our attention or any changes in law that may hereafter occur.

We express no opinion herein as to the investment quality of the Bonds or the adequacy, accuracy or completeness of any information furnished to any person in connection with any offer or sale of the Bonds.

Respectfully submitted,

STOLL KEENON OGDEN PLLC

APPENDIX B-4

(Form of Conversion Opinion of Bond Counsel)
(2008 Series A Bonds)

December 19, 2008

County of Carroll, Kentucky
Carrollton, Kentucky 41008

Deutsche Bank Trust Company Americas,
as Trustee
Summit, New Jersey 07901

Re: Conversion to Weekly Rate Period of $77,947,405 "County of Carroll, Kentucky, Environmental Facilities Revenue Bonds, 2008 Series A (Kentucky Utilities Company Project)"

Ladies and Gentlemen:

This opinion is being furnished in accordance with the requirements of the Indenture of Trust, dated as of August 1, 2008 (the "Indenture"), between the County of Carroll, Kentucky (the "Issuer") and Deutsche Bank Trust Company Americas, as Trustee (the "Trustee"), pertaining to $77,947,405 principal amount of County of Carroll, Kentucky, Environmental Facilities Revenue Bonds, 2008 Series A (Kentucky Utilities Company Project), dated October 17, 2008 (the "Bonds"), in order to satisfy certain requirements of Section 2.02(e)(i) of the Indenture. Pursuant to Section 2.02(e)(i) of the Indenture, the interest rate on the Bonds is being converted from a Flexible Rate to a Weekly Rate effective on December 19, 2008, the Conversion Date. The terms used herein denoted by initial capitals and not otherwise defined shall have the meanings specified in the Indenture.

We have examined the law and such documents and matters as we have deemed necessary to provide this opinion. As to questions of fact material to the opinions expressed herein, we have relied upon the provisions of the Indenture and related documents, and upon representations made to us without undertaking to verify the same by independent investigation.

Based upon the foregoing, as of the date hereof, we are of the opinion that the conversion of the interest rate on the Bonds as described herein (a) is authorized or permitted by the Act and the Indenture and (b) will not adversely affect the validity of the Bonds or any exclusion from gross income for federal income tax purposes to which interest on the Bonds would otherwise be entitled. Interest on the Bonds is not and will not be excluded from gross income during any period when the Bonds are held by the Company or a "related person" of the Company as defined in Section 147(a) of the Internal Revenue Code of 1986, as amended.

In rendering this opinion, we assume, without verifying, that the Issuer and the Company have complied and will comply with all covenants contained in the Indenture, the Loan Agreement between the Issuer and the Company, dated August 1, 2008, and other documents relating to the Bonds. We rendered our approving opinion at the time of the issuance of the

Bonds relating to, among other things, the validity of the Bonds and the exclusion from federal income taxation of interest on the Bonds. We have not been requested to update or continue such opinion and have not undertaken to do so. Accordingly, we do not express any opinion with respect to the Bonds except as set forth above.

Our opinion represents our legal judgment based upon our review of the law and the facts that we deem relevant to render such opinion and is not a guarantee of a result. This opinion is given as of the date hereof and we assume no obligation to review or supplement this opinion to reflect any facts or circumstances that may hereafter come to our attention or any changes in law that may hereafter occur.

We express no opinion herein as to the investment quality of the Bonds or the adequacy, accuracy or completeness of any information furnished to any person in connection with any offer or sale of the Bonds.

Respectfully submitted,

STOLL KEENON OGDEN PLLC

APPENDIX C

Commerzbank AG, New York Branch

Commerzbank Aktiengesellschaft ("Commerzbank" or the "Bank") is a major German private-sector bank. Its products and services for retail and corporate customers extend to all aspects of banking. The Bank is also active in specialized fields - partially covered by its subsidiaries - such as mortgage banking and real-estate business, leasing and asset management. Its services are concentrated on managing customers' accounts and handling payment transactions, loan, savings and investment plans, and also on securities transactions. Additional financial services are offered within the framework of the Bank's "bancassurance" strategy of cooperating with leading companies in finance-related sectors, including home loan savings schemes and insurance products. The Commerzbank Group's operating business has been categorized into six segments: Private and Business Customers, Mittelstandsbank, Central & Eastern Europe, Corporates & Markets, Commercial Real Estate as well as Public Finance and Treasury. On August 31, 2008, Commerzbank announced that Commerzbank and Allianz SE have agreed upon the sale of 100% of Dresdner Bank AG to Commerzbank. The transaction will occur in two steps and is expected to be completed by the end of 2009, subject to regulatory and antitrust approvals.

As of September 30, 2008, the Commerzbank Group had total assets of approximately 595.6 billion euros and total shareholders' equity of approximately $15.257 billion euros. The shares of Commerzbank are fully paid-up and are in bearer form. They are listed on all seven German stock exchanges as well as on the London Stock Exchange and the Swiss Exchange based in Zurich. There is also a sponsored-ADR program in the USA.

In the Federal Republic of Germany ("Germany"), Commerzbank manages a nationwide branch network covering all customer segments from its headquarters in Frankfurt am Main. Abroad, Commerzbank has branches, representative offices and key subsidiaries in approximately 50 countries.

Commerzbank conducts extensive banking business in the United States, concentrating primarily in corporate lending, letter of credit and bankers' acceptance facilities, syndicated loan transactions and treasury operations including foreign exchange transactions. Commerzbank has branches in New York, Chicago and Los Angeles and has an agency office in Atlanta.

For further information on the Commerzbank Group, a copy of Commerzbank's annual report can be obtained by contacting Ms. Karin Rapaglia at 2 World Financial Center, New York, New York 10281.

Commerzbank is authorized to conduct general banking business and to provide financial services under and, subject to the requirements set forth in, the German Banking Act (Kreditwesengesetz). The Bank is subject to comprehensive regulation and supervision by the German Financial Services Supervisory Authority (Bundesanstalt für Finanzdienstleistungsaufsicht) and by the German central bank (Deutsche Bundesbank). The European Central Bank regulates Commerzbank in relation to minimum reserves on deposits. In addition, Commerzbank is subject to regulation by the countries in which it operates.

The New York Branch of Commerzbank is licensed by the Superintendent of Banks of the State of New York. It is subject to the banking laws of the State of New York and is examined annually by the New York State Banking Department. Commerzbank's branches in Chicago and Los Angeles are subject to similar regulation by the states in which they operate. In addition to being subject to state laws and regulations, Commerzbank is also subject to federal regulation under the International Banking Act, as amended, (the "IBA") and, through the IBA, the Bank Holding Company Act, as amended, (the "BHCA"). In this regard, the Commerzbank U.S. branches and the Atlanta Agency are also examined annually by the Federal Reserve Banks in the states in which they are located.

Kentucky Utilities Company
Case No. 2009-00548
Historical Test Period Filing Requirements

Filing Requirement
807 KAR 5:001 Section 10(6)(q)
Sponsoring Witness: S. Bradford Rives

Description of Filing Requirement:

Annual report to shareholders, or members, and statistical supplements covering the two (2) most recent years from the utility's application filing date.

Response:

There are no annual reports to shareholders or members during the period referenced. KU does not publish a statistical supplement.

Federal securities rules generally require the delivery of annual reports to public shareholders when requesting their vote via certain proxy solicitations. During the period in question, the common stock of KU has been wholly-owned by E.ON U.S. LLC and no proxy solicitations occurred with respect to KU's former preferred stock (which preferred stock was ultimately redeemed in October 2005.)

(Copies of the audited annual financial statements and other financial information of KU relating to the period described are provided in Filing Requirement 807 KAR 5:001 Section 10(6)(s), [Tab No. 38].)