PPL companies

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JUN 30 2011

PUBLIC SERVICE COMMISSION

LG&E and KU Energy LLC
State Regulation and Rates
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Mr. Jeff DeRouen
Executive Director
Kentucky Public Service Commission
211 Sower Boulevard
P.O. Box 615
Frankfort, Kentucky 40602-0615

June 30, 2011

Re: ***Joint Application of PPL Corporation, E.ON AG, E.ON US Investments Corp., E.ON U.S. LLC, Louisville Gas and Electric Company, and Kentucky Utilities Company for Approval of an Acquisition of Ownership and Control of Utilities***
Case No. 2010-00204

Dear Mr. DeRouen:

Pursuant to the Commission's Order dated September 30, 2010 in the aforementioned case, Louisville Gas and Electric Company ("LG&E") and Kentucky Utilities Company ("KU"), (collectively, the "Companies") submit an original and one (1) copy of the Companies' Annual Accounting Information Filing in compliance with the reporting requirements specified in Appendix C, Commitment No. 1. In addition, the Companies are filing a copy of PPL Corporation's 2010 Annual Report pursuant to Appendix C, Commitment No. 21.

Please confirm your receipt of this filing by placing the File Stamp of your Office with date received on the extra copies. Should you have any questions regarding the information filed herewith, please call me or Don Harris at (502) 627-2021.

Sincerely,

Rick E. Lovekamp

Rick E. Lovekamp

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JUN 30 2011

PUBLIC SERVICE COMMISSION

KENTUCKY UTILITIES COMPANY
FINANCIAL STATEMENTS

MARCH 31, 2010

Kentucky Utilities Company

Financial Statements and Additional Information
(Unaudited)

As of March 31, 2010 and December 31, 2009
and for the three-month periods ended
March 31, 2010 and 2009

INDEX OF ABBREVIATIONS

AG	Attorney General of Kentucky
ARO	Asset Retirement Obligation
ASC	Accounting Standards Codification
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
CMRG	Carbon Management Research Group
Company	KU
DSM	Demand Side Management
ECR	Environmental Cost Recovery
EKPC	East Kentucky Power Cooperative, Inc.
E.ON	E.ON AG
E.ON U.S.	E.ON U.S. LLC
E.ON U.S. Services	E.ON U.S. Services Inc.
EPA	U.S. Environmental Protection Agency
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)
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
KIUC	Kentucky Industrial Utility Consumers, Inc.
KU	Kentucky Utilities Company
LG&E	Louisville Gas and Electric Company
MISO	Midwest Independent Transmission System Operator, Inc.
MMBtu	Million British thermal units
Moody's	Moody's Investors Service, Inc.
Mw	Megawatts
Mwh	Megawatt hours
NAAQS	National Ambient Air Quality Standards
NOV	Notice of Violation
NOx	Nitrogen Oxide
OMU	Owensboro Municipal Utilities
RSG	Revenue Sufficiency Guarantee
S&P	Standard & Poor's Ratings Services
SCR	Selective Catalytic Reduction
SERC	SERC Reliability Corporation
SIP	State Implementation Plan
SO_2	Sulfur Dioxide
TC1	Trimble County Unit 1
TC2	Trimble County Unit 2
VDT	Value Delivery Team Process
Virginia Commission	Virginia State Corporation Commission

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PRICEWATERHOUSECOOPERS

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

Report of Independent Accountants

To Shareholder of Kentucky Utilities Company:

We have reviewed the accompanying balance sheet of Kentucky Utilities Company as of March 31, 2010, and the related statements of income and retained earnings for the three-month periods ended March 31, 2010 and 2009 and the statements of cash flows for the three-month periods ended March 31, 2010 and 2009. This interim financial information is the responsibility of the Company's management.

We conducted our review in accordance with the standards established by the American Institute of Certified Public Accountants. A review of interim financial information consists principally of applying analytical procedures and making inquiries of persons responsible for financial and accounting matters. It is substantially less in scope than an audit conducted in accordance with auditing standards generally accepted in the United States of America, the objective of which is the expression of an opinion regarding the financial statements taken as a whole. Accordingly, we do not express such an opinion.

Based on our review, we are not aware of any material modifications that should be made to the accompanying interim financial information for it to be in conformity with accounting principles generally accepted in the United States of America.

We previously audited, in accordance with auditing standards generally accepted in the United States of America, the balance sheet of Kentucky Utilities Company as of December 31, 2009, and the related statements of income, retained earnings, and of cash flows for the year then ended (not presented herein), and in our report dated March 19, 2010, we expressed an unqualified opinion on those financial statements. In our opinion, the information set forth in the accompanying balance sheet as of December 31, 2009, is fairly stated in all material respects in relation to the balance sheet from which it has been derived.

PricewaterhouseCoopers LLP

May 14, 2010

Kentucky Utilities Company
Statements of Income
(Unaudited)
(Millions of $)

	Three Months Ended March 31, 2010	Three Months Ended March 31, 2009
Operating revenues		
Total operating revenues (Note 8)	$ 380	$ 363
Operating expenses		
Fuel for electric generation	126	115
Power purchased (Note 8)	54	64
Other operation and maintenance expenses (Note 2)	79	132
Depreciation and amortization	34	33
Total operating expenses	293	344
Net operating income	87	19
Equity in earnings of EEI	(3)	(2)
Other expense (income) – net	-	(3)
Interest expense (Note 6)	2	2
Interest expense to affiliated companies (Notes 6 and 8)	18	16
Income before income taxes	70	6
Federal and state income tax expense (benefit) (Note 5)	26	(1)
Net income	$ 44	$ 7

The accompanying notes are an integral part of these financial statements.

Statements of Retained Earnings
(Unaudited)
(Millions of $)

	Three Months Ended March 31, 2010	Three Months Ended March 31, 2009
Balance at beginning of period	$ 1,328	$ 1,195
Add net income	44	7
Balance at end of period	$ 1,372	$ 1,202

The accompanying notes are an integral part of these financial statements.

Kentucky Utilities Company
Balance Sheets
(Unaudited)
(Millions of $)

Assets	March 31, 2010	December 31, 2009
Current assets:		
Cash and cash equivalents	$ 3	$ 2
Accounts receivable, net:		
Customer – less reserves of $2 million and $1 million as of March 31, 2010 and December 31, 2009, respectively	161	155
Other – less reserves of less than $2 million as of March 31, 2010 and December 31, 2009	19	18
Accounts receivable from associated companies	-	9
Materials and supplies:		
Fuel (predominantly coal)	104	98
Other materials and supplies	40	39
Deferred income taxes – net (Note 5)	3	3
Regulatory assets (Note 2)	4	32
Prepayments and other current assets	9	10
Total current assets	343	366
Other property and investments	16	12
Utility plant:		
At original cost	4,918	4,892
Less: reserve for depreciation	1,857	1,838
Total utility plant, net	3,061	3,054
Construction work in progress	1,291	1,257
Total utility plant and construction work in progress	4,352	4,311
Deferred debits and other assets:		
Regulatory assets (Note 2):		
Pension and postretirement benefits	105	105
Other	118	117
Cash surrender value of key man life insurance	38	38
Other assets	7	7
Total deferred debits and other assets	268	267
Total assets	$ 4,979	$ 4,956

The accompanying notes are an integral part of these financial statements.

Kentucky Utilities Company
Balance Sheets (cont.)
(Unaudited)
(Millions of $)

Liabilities and Equity	March 31, 2010	December 31, 2009
Current liabilities:		
Current portion of long-term debt (Notes 3 and 6)	$ 228	$ 228
Current portion of long-term debt to affiliated company (Note 3)	33	33
Notes payable to affiliated companies (Notes 6 and 8)	28	45
Accounts payable	110	107
Accounts payable to affiliated companies (Note 8)	59	88
Accrued income taxes	17	5
Customer deposits	23	22
Regulatory liabilities (Note 2)	8	3
Other current liabilities	34	37
Total current liabilities	540	568
Long-term debt:		
Long-term bonds (Notes 3 and 6)	123	123
Long-term debt to affiliated company (Notes 3, 6 and 8)	1,298	1,298
Total long-term debt	1,421	1,421
Deferred credits and other liabilities:		
Accumulated deferred income taxes (Note 5)	345	336
Accumulated provision for pensions and related benefits (Note 4)	152	160
Investment tax credit (Note 5)	104	104
Asset retirement obligations	35	34
Regulatory liabilities (Note 2):		
Accumulated cost of removal of utility plant	336	331
Deferred income taxes - net	10	9
Postretirement benefits	9	9
MISO exit	3	4
Other	9	7
Customer advances for construction	2	3
Other liabilities	17	18
Total deferred credits and other liabilities	1,022	1,015
Common equity:		
Common stock, without par value - Authorized 80,000,000 shares, outstanding 37,817,878 shares	308	308
Additional paid-in capital (Note 8)	316	316
Retained earnings	1,358	1,318
Undistributed subsidiary earnings	14	10
Total retained earnings	1,372	1,328
Total common equity	1,996	1,952
Total liabilities and equity	$ 4,979	$ 4,956

The accompanying notes are an integral part of these financial statements.

Kentucky Utilities Company
Statements of Cash Flows
(Unaudited)
(Millions of $)

	For the Three Months Ended March 31, 2010	2009
Cash flows from operating activities:		
Net income	$ 44	$ 7
Items not requiring cash currently:		
Depreciation and amortization	34	33
Deferred income taxes – net	9	2
Investment tax credit – net	-	5
Provision for pension and post retirement plans	5	7
Other	-	2
Changes in current assets and liabilities:		
Accounts receivable	2	14
Materials and supplies	(7)	(13)
Environmental cost recovery – net	31	(3)
Accounts payable	14	37
Accrued income taxes	12	(1)
Other current assets and liabilities	(1)	(3)
Pension and postretirement funding (Note 4)	(14)	(1)
Other	(4)	(5)
Net cash provided by operating activities	125	81
Cash flows from investing activities:		
Construction expenditures	(59)	(130)
Assets purchased from affiliate	(48)	-
Change in restricted cash	-	2
Net cash used for investing activities	(107)	(128)
Cash flows from financing activities:		
Short-term borrowings from affiliated company – net (Note 6)	(17)	(3)
Additional paid-in capital (Note 8)	-	50
Net cash (used for) provided by financing activities	(17)	47
Change in cash and cash equivalents	1	-
Cash and cash equivalents at beginning of period	2	2
Cash and cash equivalents at end of period	$ 3	$ 2

The accompanying notes are an integral part of these financial statements.

Note 1 - General

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 ("Annual Report") for the year ended December 31, 2009, including the audited financial statements and notes therein.

PPL Corporation ("PPL") Acquisition

On April 28, 2010, E.ON U.S. announced that E.ON AG and E.ON US Investments Corp. had entered into a definitive agreement with PPL, a Pennsylvania corporation, to sell to PPL all the equity interests of E.ON U.S. for a base purchase price, including the assumption of debt, totaling $7.625 billion. The transaction is anticipated to close by the end of 2010, subject to completion of all the conditions precedent to its consummation. These conditions include the approval of the Kentucky Commission, the Virginia Commission and the Tennessee Regulatory Authority under state utilities laws, the approval of the FERC under the Federal Power Act and the filing of required notices with the Department of Justice and the Federal Trade Commission under the Hart-Scott-Rodino Antitrust Improvements Act of 1976 and the application of relevant waiting periods.

Certain reclassification entries have been made to the previous years' financial statements to conform to the 2010 presentation with no impact on net assets, liabilities and capitalization or previously reported net income and net cash flows.

RECENT ACCOUNTING PRONOUNCEMENTS

Fair Value Measurements

In January 2010, the FASB issued guidance related to fair value measurement disclosures requiring separate disclosure of amounts of significant transfers in and out of level 1 and level 2 fair value measurements and separate information about purchases, sales, issuances, and settlements within level 3 measurements. This guidance is effective for the first reporting period beginning after issuance except for disclosures about the roll-forward of activity in level 3 fair value measurements. This guidance has no impact on the Company's results of operations, financial position, liquidity or disclosures.

Note 2 - Rates and Regulatory Matters

For a description of each line item of regulatory assets and liabilities and for descriptions of certain matters which may not have undergone material changes relating to the period covered by this quarterly report, reference is made to Note 2 of KU's Annual Report for the year ended December 31, 2009.

2010 Kentucky Rate Case

In January 2010, KU filed an application with the Kentucky Commission requesting an increase in base electric rates of approximately 12%, or $135 million annually, including an 11.5% return on equity. KU requested the increase, based on the twelve month test year ended October 31, 2009, to become effective on and after March 1, 2010. The requested rates have been suspended until August 1, 2010, at which time they may be put into effect, subject to refund, if the Kentucky Commission has not issued an order in the proceeding. The parties are currently exchanging data requests and other filings in the proceedings and a hearing date has been scheduled for June 2010. A number of intervenors have entered the rate case, including the Kentucky Attorney General's office, certain representatives of industrial and low-income groups and other third parties, and submitted filings challenging the Companies' requested rate increases, in whole or in part. An order in the proceeding may occur during the third or fourth quarters of 2010.

2008 Kentucky Rate Case

In January 2009, KU, the AG, KIUC and all other parties to the base rate case filed a settlement agreement with the Kentucky Commission. Under the terms of the settlement agreement, KU's base rates decreased $9 million annually. An Order approving the settlement was received in February 2009, and the new rates were implemented effective February 6, 2009. In connection with the application and effective date of the new rates, the VDT surcredit and merger surcredit terminated, resulting in increased revenues of approximately $16 million annually.

Virginia Rate Case

In June 2009, KU filed an application with the Virginia Commission requesting an increase in electric base rates for its Virginia jurisdictional customers in an amount of $12 million annually or approximately 21%. The proposed increase reflected a proposed rate of return on rate base of 8.586% based upon a return on equity of 12%. During December 2009, KU and the Virginia Commission Staff agreed to a Stipulation and Recommendation authorizing base rate revenue increases of $11 million annually and a return on rate base of 7.846% based on a 10.5% return on common equity. A public hearing was held during January 2010. As permitted, pursuant to a Virginia Commission Order, KU elected to implement the proposed rates effective November 1, 2009, on an interim basis. In March 2010, the Virginia Commission issued an Order approving the stipulation, with the increased rates to be put into effect as of April 1, 2010. As part of the stipulation, KU will refund certain amounts collected since November 2009, consisting of interim rates in excess of the ultimate approved rates. These refunds aggregate approximately $1 million and are anticipated to occur during the second quarter of 2010.

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 requested a shift from current, all-in stated unit charge rates to an unbundled formula rate. In May 2009, as a result of settlement negotiations, KU submitted an unopposed motion informing the FERC of the filing of a settlement agreement and agreed-upon seven-year service agreements with the municipal customers. The unopposed motion requested interim rate structures containing terms corresponding to the overall settlement principles, to be effective from May 1, 2009, until FERC approval of the settlement agreement. The settlement and service agreements provide for unbundled formula rates which are subject to annual adjustment and approval processes. In May 2009, the FERC issued an Order approving the interim settlement with respect to rates effective May 1, 2009, representing increases of approximately 3% from prior charges and a return on equity of 11%. Additionally, during May 2009, KU filed the first annual adjustment to the formula rates to incorporate 2008 data, which adjusted formula rates became effective on July 1, 2009, and were approved by the FERC during September 2009. In May 2010, KU submitted to the FERC the 2009 update to KU's FERC-jurisdictional wholesale requirements formula rate. The updated rate will go into effect on July 1, 2010, pending review by KU's FERC-jurisdictional wholesale requirements customers and review by the FERC, which could require a refund if the customers and/or the FERC identify inappropriate costs or charges.

Separately, the parties were not able to reach agreement on the issue of whether KU must allocate to the municipal customers a portion of renewable resources it may be required to procure on behalf of its retail ratepayers. In August 2009, the FERC accepted the issue for briefing and the parties completed briefing submissions during 2009. An order by the FERC on this matter may occur during 2010. KU is not currently able to predict the outcome of this proceeding, including whether its wholesale customers may or may not be entitled to certain rights or benefits relating to renewable energy, and the financial or operational effects, if any, of such outcomes.

Regulatory Assets and Liabilities

The following regulatory assets and liabilities were included in KU's Balance Sheets:

(in millions)	March 31, 2010	December 31, 2009
Current regulatory assets:		
ECR	$ -	$ 28
FAC	-	1
MISO exit	2	2
Other	2	1
Total current regulatory assets	$ 4	$ 32
Non-current regulatory assets:		
Storm restoration	$ 59	$ 59
ARO	31	30
Unamortized loss on bonds	12	12
MISO exit	8	9
Other	8	7
Subtotal non-current regulatory assets	118	117
Pension benefits	105	105
Total non-current regulatory assets	$ 223	$ 222

	March 31, 2010	December 31, 2009
Current regulatory liabilities:		
DSM	$ 4	$ 3
ECR	2	-
Other	2	-
Total current regulatory liabilities	$ 8	$ 3
Non-current regulatory liabilities:		
Accumulated cost of removal of utility plant	$ 336	$ 331
Deferred income taxes – net	10	9
Postretirement benefits	9	9
MISO exit	3	4
Other	9	7
Total non-current regulatory liabilities	$ 367	$ 360

KU does not currently earn a rate of return on the ECR and FAC regulatory assets and the Virginia levelized fuel factor included in other regulatory assets, which are separate recovery mechanisms with recovery within twelve months. No return is earned on the pension benefits regulatory asset that represents the changes in funded status of the plans. KU will recover this asset through 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. When an asset with an ARO is retired, the related ARO regulatory asset will be offset against the associated ARO regulatory liability, ARO asset and ARO liability. A return is earned on the unamortized loss on bonds, and these costs are recovered through amortization over the life of the debt. The Company is seeking recovery of the storm restoration regulatory asset and adjustments to the amortization of CMRG and KCCS contributions, included in other regulatory assets, in its current base rate cases. The Company recovers through the calculation of base rates, the amortization of the net MISO exit regulatory asset in Kentucky incurred through April 30, 2008. The Company received approval to recover the Virginia portion of this asset, as incurred through December 31, 2008, over a five year period and, due to the formula nature of its FERC rate structure, the FERC jurisdictional portion of the regulatory asset will be included in the annual updates to the rate formula. Recovery of the FERC jurisdictional pension expense, included in other assets, and the change in accounting method for spare parts, included in other liabilities, will be requested in the next FERC rate case. The Company recovers through the calculation of base rates, the amortization of the remaining regulatory assets, including other regulatory assets comprised of deferred storm costs, the East Kentucky Power Cooperative FERC transmission settlement agreement and Kentucky rate case expenses. Other regulatory liabilities include DSM, FERC jurisdictional supplies inventory and MISO administrative charges collected via base rates from May 2008 through February 5, 2009. The MISO regulatory liability will be netted against the remaining costs of withdrawing from the MISO, per a Kentucky Commission Order, in the current Kentucky base rate case.

ECR. In January 2010, the Kentucky Commission initiated a six-month review of KU's environmental surcharge for the billing period ending October 2009. An order is anticipated in the second quarter of 2010.

In June 2009, the Company filed an application for a new ECR plan with the Kentucky Commission seeking approval to recover investments in environmental upgrades and operations and maintenance costs at the Company's generating facilities. During 2009, KU reached a unanimous settlement with all parties to the case and the Kentucky Commission issued an Order approving KU's application. Recovery on customer bills through the monthly ECR surcharge for these projects began with the February 2010 billing cycle. At December 31, 2009, the Company had a regulatory asset of $28 million, which changed to a regulatory liability of $2 million at March 31, 2010, as a result of these roll-in adjustments to base rates.

FAC. In February 2010, KU filed an application with the Virginia Commission seeking approval of a decrease in its fuel cost factor beginning with service rendered in April 2010. In February 2010, the Virginia Commission recommended a change to the fuel factor KU had in its application, to which KU agreed. Following a public hearing in March 2010, and an Order in April 2010, the recommended charge became effective as of April 1, 2010, resulting in a decrease of 23% from the fuel factor in effect for April 2009 through March 2010.

In January 2010, the Kentucky Commission initiated a six-month review of KU's FAC mechanism for the expense period ended August 2009. An order is anticipated in the second quarter of 2010.

Other Regulatory Matters

Kentucky Commission Report on Storms. In November 2009, the Kentucky Commission issued a report following review and analysis of the effects and utility response to the September 2008 wind storm and the January 2009 ice storm, and possible utility industry preventative measures relating thereto. The report suggested a number of proposed or recommended preventative or responsive measures, including consideration of selective hardening of facilities, altered vegetation management programs, enhanced customer outage communications and similar measures. In March 2010, the Companies filed a joint response reporting on their actions with respect to such recommendations. The response indicated implementation or completion of substantially all of the recommendations, including, among other matters, on-going reviews of system hardening and vegetation management procedures, certain test or pilot programs and implementation of enhanced operational and customer outage-related systems.

Wind Power Agreements. In August 2009, KU and LG&E filed a notice of intent with the Kentucky Commission indicating their intent to file an application for approval of wind power purchase contracts and cost recovery mechanisms. The contracts were executed in August 2009, and were contingent upon KU and LG&E receiving acceptable regulatory approvals. Pursuant to the proposed 20-year contracts, KU and LG&E would jointly purchase respective assigned portions of the output of two Illinois wind farms totaling an aggregate 109.5 Mw. In September 2009, the Companies filed an application and supporting testimony with the Kentucky Commission. In October 2009, the Kentucky Commission issued an Order denying the Companies' request to establish a surcharge for recovery of the costs of purchasing wind power. The Kentucky Commission stated that such recovery constitutes a general rate adjustment and is subject to the regulations of a base rate case. The Kentucky Commission Order provided for the request for approval of the wind power agreements to proceed independently from the request to recover the costs thereof via surcharges. In November 2009, KU and LG&E filed for rehearing of the Kentucky Commission's Order and requested that the matters of approval of the contract and recovery of the costs thereof remain the subject of the same proceeding. During December 2009, the Kentucky Commission issued data requests on this matter.

In March 2010, KU and LG&E delivered notices of termination under provisions of the wind power contracts. The Companies also filed a motion with the Kentucky Commission noting the termination of the contracts and seeking withdrawal of their application in the related regulatory proceeding. In April 2010, the Kentucky Commission issued an Order allowing the Companies to withdraw their pending application.

Trimble County Asset Transfer and Depreciation. KU and LG&E are currently constructing a new base-load, coal fired unit, TC2, which will be jointly owned by the Companies, together with the IMEA and the IMPA. In July 2009, the Companies notified the Kentucky Commission of the proposed sale from LG&E to KU of certain ownership interests in certain existing Trimble County generating station assets which are anticipated to provide joint or common use in support of the jointly-owned TC2 generating unit under construction at the station. The undivided ownership interests being sold are intended to provide KU an ownership interest in these common assets that is proportional to its interest in TC2 and the assets' role in supporting both TC1 and TC2. In December 2009, KU and LG&E completed the sale transaction at a price of $48 million, representing the current net book value of the assets, multiplied by the proportional interest being sold.

In August 2009, in a separate proceeding, KU and LG&E jointly filed an application with the Kentucky Commission to approve new depreciation rates for applicable TC2-related generating, pollution control and other plant equipment and assets. The filing requests common depreciation rates for the applicable jointly-owned TC2-related assets, rather than applying differing depreciation rates in place with respect to KU's and LG&E's separately-owned base-load generating assets. During December 2009, the Kentucky Commission extended the data discovery process through January 2010, and authorized KU and LG&E on an interim basis to begin using the depreciation rates for TC2 as proposed in the application. In March 2010, the Kentucky Commission issued a final Order approving the use of the proposed depreciation rates on a permanent basis.

TC2 CCN Application and Transmission Matters. An application for a CCN for construction of TC2 was approved by the Kentucky Commission in November 2005. CCNs for two transmission lines associated with TC2 were issued 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 property owners in Hardin County, Kentucky. 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. A motion for discretionary review of that reversal was filed by KU and LG&E with the Kentucky Supreme Court and was granted in April 2009. That proceeding, which seeks reinstatement of the Circuit Court dismissal of the CCN challenge, has been fully briefed and oral argument occurred during March 2010. A ruling on the matter could occur by mid 2010.

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 the transmission line in some of these forums as well.

During 2008, KU obtained various successful rulings at the Hardin County Circuit Court confirming its condemnation rights. In August 2008, several landowners appealed such rulings to the Kentucky Court of Appeals and received a temporary stay preventing KU from accessing their properties. In April 2009, that appellate court denied KU's motion to lift the stay and issued an Order retaining the stay until a decision on the merits of the appeal. Efforts to seek reconsideration of that ruling, or to obtain intermediate review of the ruling by the Kentucky Supreme Court, were unsuccessful, and the stay remains in effect. In April 2010, the Kentucky Court of Appeals issued an Order affirming the Hardin Circuit Court's finding that KU had the right to condemn easements on the properties, which appellate Order remains subject to certain reconsideration or appeals rights of the parties.

Settlement discussions with the Hardin County property owners involved in the appeals of the condemnation proceedings have been unsuccessful to date. 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.

As a result of the aforementioned unresolved litigation delays encountered in obtaining access to certain properties in Hardin County, KU has obtained easements to allow construction of temporary transmission facilities bypassing those properties while the litigated issues are resolved. In September 2009, the Kentucky Commission issued an Order stating that a CCN was necessary for two segments of the proposed temporary facilities. In December 2009, the Kentucky Commission granted the CCNs for the relevant segments and the property owners have filed various motions to intervene, stay and appeal certain elements of the Kentucky Commission's recent orders. In January 2010, in respect of two of such proceedings, the Franklin County circuit court issued Orders denying the property owners' request for a stay of construction and upholding the prior Kentucky Commission denial of their intervenor status. In parallel with, and consistent with the relevant legal proceedings and their status, the Company is proceeding with the construction activities with respect to these temporary transmission facilities.

In a separate proceeding, certain Hardin County landowners have also challenged the same transmission line in federal district court in Louisville, Kentucky. In that action, the landowners claim that the U.S. Army failed to comply with certain National Historic Preservation Act requirements 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 and in October 2009, the federal court granted the defendants' motion for summary judgment and dismissed the plaintiffs' claims. During November 2009, the petitioners filed submissions for review of the decision with the 6th Circuit Court of Appeals.

KU and LG&E are not currently able to predict the ultimate outcome and possible effects, if any, on the construction schedule relating to the transmission line approval, land acquisition and permitting proceedings.

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 the Company from the requirements of the new hybrid model of regulation. In lieu of submitting an annual information filing, the Company 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.

Market-Based Rate Authority. In July 2006, the FERC issued an Order in KU's market-based rate proceeding accepting the Company'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 the Company'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. As a condition of receiving and retaining market-based rate authority, KU must comply with applicable affiliate restrictions set forth in the FERC regulation. During September 2008, the Company submitted a regular tri-annual update filing under market-based rate regulations.

In June 2009, the FERC issued Order No. 697-C which generally clarified certain interpretations relating to power sales and purchases at control area interfaces or into control areas involving market power. In July 2009, the FERC issued an order approving the Company's September 2008 application for market-based rate authority. During July 2009, affiliates of KU completed a transaction terminating certain prior generation and power marketing activities in the Big Rivers Electric Corporation control area, which termination should ultimately allow a filing to request a determination that the Company no longer is deemed to have market power in such control area.

KU conducts certain of its wholesale power sales activities in accordance with existing market-based rate authority principles and interpretations. Future FERC proceedings relating to Orders 697 or market-based rate authority could alter the amount of sales made at market-based versus cost-based rates. The Company's sales under market-based rate authority totaled less than $1 million for the year ended March 31, 2010.

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 Regional Reliability Organizations ("RROs") by the North American Electric Reliability Corporation ("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 and LG&E are members of the SERC Reliability Corporation ("SERC"), which acts as KU's and LG&E's RRO. During December 2009, the SERC and KU and LG&E agreed to settlements involving penalties totaling less than $1 million for each utility related to their self-reports during

June and October 2008, concerning possible violations of standards. During December 2009 and April 2010, KU and LG&E submitted self-reports relating to additional standards, the resolution of which the Companies do not anticipate will result in material penalties or remedial actions, but which processes remain in the early stages and therefore the Companies are unable to determine the outcome. 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. While KU and LG&E believe they are in compliance with the mandatory reliability standards, they cannot predict the outcome of other analyses, including on-going SERC or other reviews described above.

Integrated Resource Plan. Pursuant to the Virginia Commission's December 2008 Order, KU filed its Integrated Resource Plan ("IRP") in July 2009. The filing consisted of the 2008 Joint IRP filed by KU and LG&E with the Kentucky Commission along with additional data. During March 2010, the Virginia Commission Staff issued a staff report acknowledging that KU fairly and adequately evaluated all resource options, documented and supported all critical model assumptions and methodologies, and complied with all legislative requirements and Virginia Commission guidelines.

Green Energy Riders. 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 ("REC") through June 1, 2010. During November 2009, KU and LG&E filed an application to both continue and modify the existing Green Energy Programs. In February 2010, the Kentucky Commission approved the Companies' application, as filed.

Note 3 - Financial Instruments

The cost and estimated fair values of KU's non-trading financial instruments as of March 31, 2010 and December 31, 2009 follows:

	March 31, 2010		December 31, 2009	
(in millions)	Carrying Value	Fair Value	Carrying Value	Fair Value
Long-term debt (including current portion of $228 million)	$ 351	$ 351	$ 351	$ 351
Long-term debt from affiliate (including current portion of $33 million)	$ 1,331	$ 1,409	$ 1,331	$ 1,401

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. The Company'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 March 31, 2010, a 100 basis point change in the benchmark rate on KU's variable rate debt would impact pre-tax interest expense by $4 million annually. Although the Company's policies allow for the use of interest rate swaps, as of March 31, 2010 and December 31, 2009, KU had no interest rate swaps outstanding.

The Company is subject to interest rate and commodity price risk related to on-going business operations. It currently manages these risks using derivative financial instruments, including swaps and forward contracts.

KU has classified the applicable financial assets and liabilities that are accounted for at fair value into the three levels of the fair value hierarchy, as defined by the Fair Value Measurements and Disclosures topic of the FASB ASC, as follows:

- Level 1 - Observable inputs that reflect quoted prices (unadjusted) for identical assets or liabilities in active markets.
- Level 2 - Include other inputs that are directly or indirectly observable in the marketplace.
- Level 3 - Unobservable inputs which are supported by little or no market activity.

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 the Derivatives and Hedging topic of the FASB ASC.

Energy trading and risk management contracts are valued using prices based on active trades from Intercontinental Exchange Inc. In the absence of a traded price, midpoints of the best bids and offers are the primary determinants of valuation. When sufficient trading activity is unavailable, other inputs 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 measurement criteria in the Fair Value Measurements and Disclosures topic of the FASB ASC. 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 2010 or 2009. Changes in market pricing, interest rate and volatility assumptions were made during both years.

The Company maintains credit policies intended to minimize credit risk in wholesale marketing and trading activities by assessing the creditworthiness of potential counterparties prior to entering into transactions with them and continuing to evaluate their creditworthiness once transactions have been initiated. To further mitigate credit risk, KU seeks to enter into netting agreements or require cash deposits, letters of credit and parental company guarantees as security from counterparties. The Company uses S&P, Moody's and definitive qualitative and quantitative data to assess the financial strength of counterparties on an on-going basis. If no external rating exists, KU assigns an internally generated rating for which it sets appropriate risk parameters. As risk management contracts are valued based on changes in market prices of the related commodities, credit exposures are revalued and monitored on a daily basis. At March 31, 2010, 100% of the trading and risk management commitments were with counterparties rated

BBB-/Baa3 equivalent or better. The Company 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 March 31, 2010, and December 31, 2009, counterparty credit reserves related to the energy trading and risk management contracts were less than $1 million.

The net volume of electricity based financial derivatives outstanding at March 31, 2010 and December 31, 2009, was zero Mwhs and 43,400 Mwhs, respectively. No cash collateral related to the energy trading and risk management contracts was required at March 31, 2010. Cash collateral related to the energy trading and risk management contracts was less than $1 million at December 31, 2009. Cash collateral related to the energy trading and risk management contracts is categorized as other accounts receivable and is a level 1 measurement based on the funds being held in liquid accounts.

The following table sets forth by level within the fair value hierarchy, KU's financial assets and liabilities that were accounted for at fair value on a recurring basis as of March 31, 2010. Financial assets as of December 31, 2009 and financial liabilities as of March 31, 2010 and December 31, 2009, arising from energy trading and risk management contracts accounted for at fair value total less than $1 million and use level 2 measurements. There are no level 3 measurements for the periods ending March 31, 2010 and December 31, 2009.

Recurring Fair Value Measurements (in millions)
March 31, 2010

	Level 1	Level 2	Total
Financial Assets:			
Energy trading and risk management contracts	$ -	$ 1	$ 1
Total Financial Assets	$ -	$ 1	$ 1

The Company does not net collateral against derivative instruments.

Certain of the Company's derivative instruments contain provisions that require the Company to provide immediate and on-going collateralization on derivative instruments in net liability positions based upon the Company's credit ratings from each of the major credit rating agencies. At March 31, 2010, there are no energy trading and risk management contracts with credit risk related contingent features that are in a liability position, and no collateral posted in the normal course of business. At March 31, 2010, a one notch downgrade of the Company's credit rating would have no effect on the energy trading and risk management contracts or collateral required as a result of these contracts.

The table below shows the fair value and balance sheet location of derivatives not designated as hedging instruments as of March 31, 2010:

(in millions)	Asset Derivatives Balance Sheet Location	Fair Value
Energy trading and risk management contracts	Other current Assets	$ 1
Total		$ 1

At December 31, 2009, the fair value of short-term assets for energy trading and risk management contracts not designated as hedging instruments was less than $1 million. At March 31, 2010 and December 31, 2009, the fair value of short-term liabilities for energy trading and risk management contracts not designated as hedging instruments was less than $1 million, respectively.

KU manages the price risk of its estimated future excess economic generation capacity using market-traded forward contracts. Hedge accounting treatment has not been elected for these transactions, and therefore gains and losses are shown in the statements of income.

The following table presents the effect of derivatives not designated as hedging instruments on income for the three months ended March 31:

(in millions)	Location of Gain (Loss) Recognized in Income on Derivatives	Amount of Gain (Loss) Recognized in Income on Derivatives	
		Three Months Ended March 31, 2010	Three Months Ended March 31, 2009
Energy trading and risk management contracts (unrealized)	Electric revenues	$ -	$ 2
Total		$ -	$ 2

Net unrealized gains and losses were less than $1 million in the three month period ended March 31, 2010. Net realized gains and losses were less than $1 million in the three month periods ended March 31, 2010 and March 31, 2009.

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 for the three months ended March 31. The tables include the costs associated with both KU employees and E.ON U.S. Services employees who are providing services to the Company. The E.ON U.S. Services costs that are allocated to KU are approximately 53% and 51% of E.ON U.S. Services costs for March 31, 2010 and 2009, respectively.

(in millions)	Pension Benefits Three Months Ended March 31, 2010			2009		
	KU	E.ON U.S. Services Allocation to KU	Total KU	KU	E.ON U.S. Services Allocation to KU	Total KU
Service cost	$ 2	$ 1	$ 3	$ 2	$ 1	$ 3
Interest cost	5	2	7	5	2	7
Expected return on plan assets	(4)	(1)	(5)	(4)	(1)	(5)
Amortization of actuarial loss	1	1	2	2	1	3
Benefit cost	$ 4	$ 3	$ 7	$ 5	$ 3	$ 8

(in millions)	Other Postretirement Benefits Three Months Ended March 31, 2010			2009		
	KU	E.ON U.S. Services Allocation to KU	Total KU	KU	E.ON U.S. Services Allocation to KU	Total KU
Service cost	$ 1	$ -	$ 1	$ 1	$ 1	$ 2
Interest cost	1	-	1	1	-	1
Benefit cost	$ 2	$ -	$ 2	$ 2	$ 1	$ 3

In January 2010, KU made a contribution to a pension plan covering its employees of $13 million. In addition, E.ON U.S. Services made a pension plan contribution of $9 million. KU's intent is to fund the pension plan in a manner consistent with the requirements of the Pension Protection Act of 2006.

In 2010, KU has made contributions to other postretirement benefit plans totaling $1 million. The Company also anticipates further funding to match the annual postretirement expense and funding the 401(h) plan up to the maximum amount allowed by law.

Note 5 - 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. The Company also files income tax returns in various state jurisdictions. While 2006 and later years are open under the federal statute of limitations, Revenue Agent Reports for 2006-2007 have been received from the IRS, effectively closing these years to additional audit adjustments. Adjustments to these tax years were previously recorded in the financial statements. Tax years 2007 and 2008 were 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. Areas remaining under examination for 2008 include bonus depreciation and the Company's application for a change in repair deductions. No net material adverse impact is expected from these remaining areas.

Additions and reductions of uncertain tax positions during 2010 and 2009 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. If recognized, the less than $1 million of unrecognized tax benefits would reduce the effective income tax rate.

The amount KU recognized as interest expense and interest accrued related to unrecognized tax benefits was less than $1 million as of March 31, 2010 and December 31, 2009. The interest expense and interest accrued is based on IRS and Kentucky Department of Revenue large corporate interest rates for underpayment of taxes. At the date of adoption, the Company accrued less than $1 million in interest expense on uncertain tax positions. KU records the interest as interest expense and penalties as operating expenses in the income statement and accrued expenses in the balance sheet, on a pre-tax basis. No penalties were accrued by the Company through March 31, 2010.

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 $101 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 $5 million during the three months ended March 31, 2009 decreasing current federal income taxes. The amount claimed through 2009 is all that KU is allowed to claim. KU has recorded the maximum credit of $101 million. In addition, a full depreciation basis adjustment is required for the amount of the credit. The income tax expense impact from amortizing these credits 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. During 2008 and 2009, the plaintiffs submitted amended complaints alleging additional claims for relief. In October 2009, the plaintiffs filed a motion for a preliminary injunction seeking temporary implementation of certain elements of the requested relief. The Company is not currently a party to this proceeding and is not able to predict the ultimate outcome of this matter.

In the first quarter 2010, KU recorded an income tax expense of less than $1 million to recognize the impact of the elimination of the tax deduction related to Medicare Part D subsidy as required with enactment of the Patient Protection and Affordable Care Act.

Note 6 - Short-Term and Long-Term Debt

KU's long-term debt includes $228 million of pollution control bonds that are 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 2002 Series A and B, 2004 Series A, 2006 Series B and 2008 Series A; Muhlenberg County 2002 Series A; and Mercer County 2000 Series A and 2002 Series A. Maturity dates for these bonds range from 2023 to 2034. The average annualized interest rate for these bonds during the three months ended March 31, 2010 was 0.36%.

Pollution control bonds are obligations of KU issued in connection with tax-exempt pollution control revenue bonds issued by counties in Kentucky. A loan agreement obligates the Company 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. The loan agreement is an unsecured obligation of the Company. Proceeds from bond issuances for environmental equipment (primarily related to the installation of FGDs) were held in trust pending expenditure for qualifying assets. At March 31, 2010 and December 31, 2009, KU had no bond proceeds in trust included in restricted cash on the balance sheet.

Several of the KU pollution control bonds are insured by monoline bond insurers whose ratings have been reduced due to exposures relating to insurance of sub-prime mortgages. At March 31, 2010, 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. During 2008, interest rates increased, and the Company experienced "failed auctions" when there were insufficient bids for the bonds. When a failed auction occurs, the interest rate is set pursuant to a formula stipulated in the indenture. During the three months ended March 31, 2010 and 2009, the average rate on the auction rate bonds was 0.27% and 0.65%, 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 June 2009, S&P downgraded the credit rating of Ambac, an insurer of the Company's bonds, from "A" to "BBB". As a result, S&P downgraded the rating on the Carroll County 2002 Series C bond from "A" to "BBB+" in June 2009. The S&P rating of this bond is now based on the rating of the Company rather than the rating of Ambac since the Company's rating is higher.

The Company 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
March 31, 2010	$ 400	$ 28	$ 372	0.21%
December 31, 2009	$ 400	$ 45	$ 355	0.20%

E.ON U.S. maintains revolving credit facilities totaling $313 million at March 31, 2010 and December 31, 2009, to ensure funding availability for the money pool. At March 31, 2010, 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 balances are as follows:

($ in millions)	Total Available	Amount Outstanding	Balance Available	Average Interest Rate
March 31, 2010	$ 313	$ 164	$ 149	1.47%
December 31, 2009	$ 313	$ 276	$ 37	1.25%

As of March 31, 2010, the Company maintained a bilateral line of credit, with an unaffiliated financial institution, totaling $35 million which matures in June 2012. At March 31, 2010, there was no balance outstanding under this facility. The Company also maintains letter of credit facilities that support $195 million of the $228 million of bonds that can be put back to the Company. Should the holders elect to put the bonds back and they cannot be remarketed, the letter of credit would fund the investor's payment.

There were no redemptions or issuances of long-term debt year-to-date through March 31, 2010.

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 the Company's Annual Report for the year ended December 31, 2009 (including, but not limited to Notes 2, 9 and 12 to the financial statements of KU contained therein). See the Company's Annual Report regarding such commitments or contingencies.

Owensboro Contract Litigation. In May 2004, the City of Owensboro, Kentucky and OMU commenced a suit which was 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 involved 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. In July 2005, the court issued a summary judgment ruling upholding OMU's contractual right to terminate the OMU agreement in May 2010.

In September and October 2008, the court granted rulings on a number of summary judgment petitions in the Company's favor. The summary judgment rulings resulted in the dismissal of all of OMU's remaining claims against the Company. 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 the Company 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, plus pre- and post-judgment interest, and (ii) denying the Company's claim for damages based upon sub-par operations and availability of the OMU units. In April 2009, the court issued a ruling on various post-trial motions denying certain challenges to calculation elements of the $9 million award or of interest amounts associated therewith. In May 2009, KU and OMU executed a settlement agreement resolving the matter on a basis consistent with the court's prior rulings and the Company has received the agreed settlement amounts. Therefore, pursuant to the settlement's operation, the OMU agreement will terminate in May 2010, as described above.

Construction Program. KU had approximately $50 million of commitments in connection with its construction program at March 31, 2010.

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. In March 2009, the parties completed an agreement resolving certain 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. The Company's share of additional costs from inception of the contract through the expected project completion in 2010 is estimated to be approximately $35 million. During the past and to date in 2010, KU and LG&E have received a number of contractual notices from the TC2 construction contractor asserting force majeure/excusable event claims for additional adjustments to either or both of contract price or construction schedule with respect to certain events which, if granted, may affect such contractual terms in addition to a possible extension of the commercial operations date, liquidated damages or other relevant provisions. The parties are continuing to discuss such matters in good faith and are attempting to resolve them in a commercially reasonable manner. The Company cannot currently estimate the ultimate outcome of these matters, including the extent, if any, that may result in increased costs charged for construction of TC2 and/or relief relating to the construction completion or operations dates.

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. In September 2007, the Secretary of the Kentucky Environmental and Public Protection Cabinet issued a final Order upholding the permit. The environmental groups petitioned the EPA to object to the state permit and subsequent permit revisions. In determinations made in September 2008 and June 2009, the EPA rejected most of the environmental groups' claims, but identified three permit deficiencies which the KDAQ addressed by revising the permit. In August 2009, the EPA issued an order denying the remaining claims with the exception of two additional deficiencies which the KDAQ was directed to address. The EPA determined that the proposed permit subsequently issued by the KDAQ satisfied the conditions of the EPA Order, although the agency recommended certain enhancements to the administrative record. In January 2010, the KDAQ issued a final permit revision incorporating the proposed changes to address the EPA objections. In March 2010, the environmental groups submitted a petition to the EPA to object to the permit revision, which petition is now pending before the EPA. The Company believes that the final permit as revised should not have a material adverse effect on its financial condition or results of operations. However, until the EPA issues a final ruling on the petition and all applicable appeals have been exhausted, the Company cannot predict the final outcome of this matter.

Thermostat Replacement. During January 2010, KU and LG&E announced a voluntary plan to replace certain thermostats which had been provided to customers as part of the Companies' demand reduction programs, due to concerns that the thermostats may present a safety hazard. Under the plan, the Companies anticipate replacing up to approximately 14,000 thermostats. Estimated costs associated with the replacement program may be $2 million. However, the

Companies cannot fully predict the ultimate outcome of the replacement program or other effects or developments which may be associated with the thermostat replacement matter at this time.

Environmental Matters. The Company'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 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 January 2010, EPA issued a proposed rule to reconsider the NAAQS for Ozone, previously revised in 2008. The proposal would institute more stringent standards. At present, the Company 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 place 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 the Companies' compliance plans relating thereto, due to the interconnection of the CAIR 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 Clean Air Act, as amended, 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 Clean Air Mercury Rule ("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 rules with different or more stringent requirements for reduction of mercury and other hazardous air pollutants. 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 Clean Air Act, as amended, 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 Clean Air Act, as amended, also contains 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 ("CAVR") detailing how the Clean Air Act's Best Available Retrofit Technology ("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 through 2009 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 $320 million during the 2010 through 2012 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.

GHG Developments. 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. As discussed below, 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. The current administration has announced its support for the adoption of mandatory GHG reduction requirements at the federal level. The United States and other countries met in Copenhagen, Denmark in December 2009, in an effort to negotiate a GHG reduction treaty to succeed the Kyoto Protocol, which is set to expire in 2013. At Copenhagen, the U.S. made a nonbinding commitment to, among other things, seek to reduce GHG emissions to 17% below 2005 levels by 2020 and provide financial support to developing countries. The United States and other nations are scheduled to meet in Cancun, Mexico in late 2010 to continue negotiations toward a binding agreement.

GHG Legislation KU is monitoring on-going efforts to enact GHG reduction requirements and requirements governing carbon sequestration at the state and federal level and is assessing potential impacts of such programs and strategies to mitigate those impacts. In June 2009, the U.S. House of Representatives passed the American Clean Energy and Security Act of 2009, (H.R. 2454), which is a comprehensive energy bill containing the first-ever nation-wide GHG cap and trade program. The bill would provide for reductions in GHG emissions of 3% below 2005 levels by 2012, 17% by 2020, and 83% by 2050. In order to cushion potential rate impacts for utility customers, approximately 43% of emissions allowances would initially be allocated at no cost to the electric utility sector, with this allocation gradually declining to 7% in 2029 and zero thereafter. The bill would also establish a renewable electricity standard requiring utilities to meet 20% of their electricity demand through renewable energy and energy efficiency by 2020. The bill contains additional provisions regarding carbon capture and sequestration, clean transportation, smart grid advancement, nuclear and advanced technologies and energy efficiency.

In September 2009, the Clean Energy Jobs and American Power Act (S. 1733), which is largely patterned on the House legislation, was introduced in the U.S. Senate. The Senate bill raises the emissions reduction target for 2020 to 20% below 2005 levels and does not include a renewable electricity standard. While the initial bill lacked detailed provisions for the allocation of emissions allowances, a subsequent revision incorporated allowance allocation provisions similar to the House bill. More recently, Senators Kerry, Lieberman and others have announced that they are currently working on GHG legislation covering the utility and transportation sectors that would provide for a 17% reduction in GHG emissions by 2020, but have introduced no bill in the Senate to date. The Company is closely monitoring the progress of the legislation, although the prospect for passage of comprehensive GHG legislation in 2010 is uncertain.

GHG Regulations. In April 2007, the U.S. Supreme Court ruled that the EPA has the authority to regulate GHG under the Clean Air Act. In April 2009, the EPA issued a proposed endangerment finding concluding that GHGs endanger public health and welfare, which is an initial rulemaking step under the Clean Air Act. A final endangerment finding was issued in December 2009. In September 2009, the EPA issued a final GHG reporting rule requiring reporting by facilities with annual GHG emissions equivalent to at least 25,000 tons of carbon dioxide. A number of the Company's facilities will be required to submit annual reports commencing with calendar year 2010. Also in September 2009, the EPA proposed the GHG "tailoring" rule requiring new or modified sources with GHG emissions equivalent to at least 10,000 to 25,000 tons of carbon dioxide to obtain permits under the Prevention of Significant Deterioration Program. Such new or modified facilities would be required to install Best Available Control Technology. While the Company is unaware of any currently available GHG control technology that might be required for installation on new or modified power plants, it is currently assessing the potential impact of the proposed rule. A final tailoring rule is expected in 2010. The EPA has announced that the final tailoring rule will address the phase in of GHG regulation for these stationary sources and will provide for regulation of new or modified stationary sources such as power plants in 2011.

The Company is unable to predict whether mandatory GHG reduction requirements will ultimately be enacted through legislation or regulations. 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 its operations, including the reduction targets and deadlines that would be applicable, cannot be determined prior to the enactment of such programs. While the Company believes that many costs of complying with mandatory GHG reduction requirements or purchasing emission allowances to meet applicable requirements would likely be recoverable, in whole or in part under the ECR, where such costs are related to the Company's coal-fired generating assets, or other potential cost-recovery mechanisms, this cannot be assured.

GHG Litigation. A number of lawsuits have been filed asserting common law claims including nuisance, trespass and negligence against various companies with GHG emitting facilities. In October 2009, a three judge panel of the United States Court of Appeals for the 5th Circuit in the case of Comer v. Murphy Oil reversed a lower court, holding that private plaintiffs have standing to assert certain common law claims against more than 30 utility, oil, coal and chemical companies. However, in March 2010, the court vacated the opinion of the three-judge panel and granted a motion for rehearing. The Comer complaint alleges that GHG emissions from the defendants' facilities contributed to global warming which increased the intensity of Hurricane Katrina. E.ON, the parent of KU and LG&E was included as a defendant in the complaint, but has not been subject to the proceedings due to the failure of the plaintiffs to pursue service under the applicable international procedures. KU and LG&E are currently unable to predict further developments in the Comer case. KU and LG&E continue to monitor relevant GHG litigation to identify judicial developments that may be potentially relevant to their operations.

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 December 2008, the Company reached a tentative settlement with the government resolving all outstanding claims. The consent decree, which was approved by the court in March 2009, 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. The Company is currently implementing the provisions of the consent decree.

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 TC1 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. The Company is not able to estimate the outcome or potential effects of these matters, including whether substantial fines, penalties or remedial measures may result.

Ghent New Source Review NOV. In March 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 contends that the work in question, as pollution control projects, was exempt from the requirements cited by the EPA. In December 2009, the EPA issued a Section 114 information request seeking additional information on this matter. In March 2010, the Company received an

EPA settlement proposal providing for imposition of additional permit limits and emission controls and anticipates continued settlement negotiations with the EPA. Depending on the provisions of a final settlement or the results of litigation, if any, resolution of this matter could involve significant increased operating and capital expenditures. 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.

Ash Ponds, Coal-Combustion Byproducts and Water Discharges. The EPA has undertaken various initiatives in response to the December 2008 impoundment failure at the Tennessee Valley Authority's Kingston power plant, which resulted in a major release of coal combustion byproducts into the environment. The EPA issued information requests to utilities throughout the country, including KU, to obtain information on their ash ponds and other impoundments. In addition, the EPA inspected a large number of impoundments located at power plants to determine their structural integrity. The inspections included several of the KU's impoundments, which the EPA found to be in satisfactory condition. In May 2010, the EPA announced proposed regulations for coal combustion byproducts handled in landfills and ash ponds. The EPA has proposed two alternatives: (1) regulation of coal combustion byproducts in landfills and ash ponds as a hazardous waste; or (2) regulation of coal combustion byproducts as a solid waste with minimum national standards. Under both alternatives, the EPA has proposed safety requirements to address the structural integrity of ash ponds. In addition, the EPA will consider potential refinements of the provisions for beneficial reuse of coal combustion byproducts. The EPA has also announced plans to develop revised effluent limitations guidelines and standards governing discharges from power plants. The Company is monitoring these ongoing regulatory developments, but will be unable to determine the impact until such time as new rules are finalized.

In May 2010, the Sierra Club and other environmental groups filed a petition with the Kentucky Energy and Environment Cabinet challenging the Kentucky Pollutant Discharge Elimination System permit issued in April 2010, which covers water discharges from the Trimble County Station. Due to the preliminary stage of the proceedings, the Company is currently unable to predict the outcome or precise impact of this matter.

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 a completed settlement with state regulators regarding particulate limits in the air permit for KU's Tyrone generating station, remediation activities for, or other risks relating to elevated Polychlorinated Biphenyl levels at existing properties, and liability under the Comprehensive Environmental Response, Compensation and Liability Act for cleanup at various off-site waste sites. Based on analysis to date, the resolution of these matters is not expected to have a material impact on the Company's operations.

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 FERC regulations under the Public Utility Holding Company Act of 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's intercompany electric revenues and purchased power expense for the three months ended March 31, were as follows:

(in millions)	2010	2009
Electric operating revenues from LG&E	$ 7	$ 9
Purchased power from LG&E	24	31

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 for the three months ended March 31, was as follows:

(in millions)	2010	2009
Interest on Fidelia loans	$ 18	$ 16

Other Intercompany Billings

E.ON U.S. Services provides the Company 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 the Company, 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 and hourly 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 the Company on behalf of other non-regulated businesses which are reimbursed through E.ON U.S. Services.

Intercompany billings to and from KU for the three months ended March 31, were as follows:

(in millions)	2010	2009
E.ON U.S. Services billings to KU	$ 50	$ 40
KU billings to LG&E	-	11
LG&E billings to KU	8	-
KU billings to E.ON U.S. Services	-	1

In the first quarter of 2010, the Company received no capital contributions from its common shareholder, E.ON U.S. In March 2009, the Company received capital contributions of $50 million from its common shareholder, E.ON U.S.

Note 9 – Subsequent Events

Subsequent events have been evaluated through May 14, 2010, the date of issuance of these statements and these statements contain all necessary adjustments and disclosures resulting from that evaluation.

On April 28, 2010, E.ON U.S. announced that E.ON AG and E.ON US Investments Corp. had entered into a definitive agreement with PPL, a Pennsylvania corporation, to sell to PPL all the equity interests of E.ON U.S. for a base purchase price, including the assumption of debt, totaling $7.625 billion. The transaction is anticipated to close by the end of 2010, subject to completion of all the conditions precedent to its consummation. In connection with the announcement, Moody's placed the debt ratings of the Company under review for possible downgrade. S&P affirmed the existing ratings of the Company. See Note 1, General.
On April 9, 2010, the Kentucky Commission issued an Order allowing the Companies to withdraw their pending application for approval of their wind power contracts.

On April 1, 2010, KU implemented new rates in Virginia following a Virginia Commission Order. As part of the Order, KU will refund certain amounts collected since November 2009, consisting of interim increased rates in excess of the ultimate approved rates. These refunds aggregate approximately $1 million and are anticipated to occur during the second quarter of 2010.

On April 9, 2010, the Kentucky Commission issued an Order allowing the Companies to withdraw their pending application for approval of the wind power contracts.

Management's Discussion and Analysis

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 month period ended March 31, 2010, 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, 2009.

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. KU provides electric service to approximately 515,000 customers in 77 counties in central, southeastern and western Kentucky, to approximately 29,000 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 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. KU's affiliate, LG&E, is a regulated public utility engaged in the generation, transmission, distribution and sale of electric energy and the storage, distribution and sale of natural gas in Kentucky.

On April 28, 2010, E.ON U.S. announced that E.ON AG and E.ON US Investments Corp. had entered into a definitive agreement with PPL, a Pennsylvania corporation, to sell to PPL all the equity interests of E.ON U.S. for a base purchase price, including the assumption of debt, totaling $7.625 billion. The transaction is anticipated to close by the end of 2010, subject to completion of all the conditions precedent to its consummation. These conditions include the approval of the Kentucky Commission, the Virginia Commission, and the Tennessee Regulatory Authority under state utilities laws, the approval of the FERC under the Federal Power Act and the filing of required notices with the Department of Justice and the Federal Trade Commission under the Hart-Scott-Rodino Antitrust Improvements Act of 1976 and the application of relevant waiting periods.

Regulatory Matters

In January 2010, KU filed an application with the Kentucky Commission requesting an increase in base electric rates of approximately 12%, or $135 million annually, including an 11.5% return on equity. KU requested the increase, based on the twelve month test year ended October 31, 2009, to become effective on and after March 1, 2010. The requested rates have been suspended until August 1, 2010, at which time they may be put into effect, subject to refund, if the Kentucky Commission has not issued an order in the proceeding. The parties, including a number of intervenors are currently exchanging data requests and other filings in the proceedings and a hearing date has been scheduled for June 2010. An order in the proceeding may occur during the third or fourth quarters of 2010.

In January 2009, KU, the AG, KIUC and all other parties to the base rate case filed a settlement agreement with the Kentucky Commission. Under the terms of the settlement agreement, the Company's base rates decreased $9 million annually. An Order approving the settlement was received in February 2009, and the new rates were implemented effective February 6, 2009. In connection with the application and effective date of the new rates, the VDT surcredit and merger surcredit terminated, resulting in increased revenues of approximately $16 million annually.

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 incurred $57 million of incremental operation and maintenance expenses and $33 million of capital expenditures related to the restoration following the two storms. The Company filed an application with the Kentucky Commission in April 2009, requesting approval to establish a regulatory asset, and defer for future recovery, approximately $62 million in incremental operation and maintenance expenses related to the storm restoration. In September 2009, the Kentucky Commission issued an Order allowing the Company to establish a regulatory asset of up to $62 million based on its actual costs for storm damages and service restoration due to the January and February 2009 winter storms. In September 2009, the Company established a regulatory asset of $57 million for actual costs incurred, and the Company is seeking recovery of this asset in its current base rate case.

Environmental Matters

General. Protection of the environment is a major priority for KU and a significant element of its business activities. KU's properties and operations are subject to extensive environmental-related oversight by federal, state and local regulatory agencies, including via air quality, water quality, waste management and similar laws and regulations. Therefore, KU must conduct its operations in accordance with numerous permit and other requirements issued under or contained in such laws or regulations.

Climate Change. Recent developments continue to indicate an increased possibility of significant climate change or GHG legislation or regulation, at the international, federal, regional and state levels. During December 2009, as part of the United Nation's Copenhagen Accord, the United States agreed to a non-binding goal to reduce GHG emissions to 17% below 2005 levels by 2020. Additionally, during 2009, the U.S. House of Representatives passed a comprehensive GHG legislation, which included a number of measures to limit GHG emissions and achieve GHG emission reduction targets below 2005 levels of 3%, 17% and 83% by 2012, 2020 and 2050, respectively, and the U.S. Senate is considering companion legislation. In late 2009, the

EPA issued or proposed various regulatory initiatives relating to GHG matters, including an endangerment finding relating to mobile sources of GHGs, a GHG reporting requirement and a proposed rule relating to permitting requirements for new or modified GHG emission sources. Finally, a number of U.S. states, although not currently including Kentucky, have adopted GHG-reduction legislation or regulation of various sorts. The developing GHG initiatives include a number of differing structures and formats, including direct limitations on GHG sources, issuance of allowances for GHG emissions, cap-and-trade programs for such allowances, renewable or alternative generation portfolio standards and mechanisms relating to demand reduction, energy efficiency, smart-grid, transmission expansion, carbon-sequestration or other GHG-reducing efforts. While the final terms and impacts of such initiatives cannot be estimated, KU, as a primarily coal-fired utility, could be highly affected by such proceedings.

The cost to KU and the effect on KU's business of complying with potential GHG restrictions will depend upon the details of the programs ultimately enacted. Some of the design elements which may have the greatest effect on KU include (a) the required levels and timing of any carbon caps or limits, (b) the emission sources covered by such caps or limits, (c) transition and mitigation provisions, such as phase-in periods, free allowances or price caps, (d) the availability and pricing of relevant GHG-reduction technologies, goods or services and (e) economic, market and customer reaction to electricity price and demand changes due to GHG limits.

Ultimately, environmental matters or potential environmental matters can represent an important element of current or future potential capital requirements, future unit retirement or replacement decisions, supply and demand for electricity, operating and maintenance expenses or compliance risks for the Company. While KU currently anticipates that many of such direct costs or effects may be recoverable through rates or other regulatory mechanisms, particularly with respect to coal-related generation, the availability, timing or completeness of such rate recovery cannot be assured. Ultimately, climate change matters could result in material effects on KU's results of operations, liquidity and financial position. See Management's Discussion and Analysis and Note 7 of Notes to Financial Statements for additional 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 March 31, 2010, Compared to
Three Months Ended March 31, 2009

Net Income

Net income for the three months ended March 31, 2010, increased $37 million compared to the same period in 2009. The increase was primarily the result of decreased operating expense ($51 million), increased electric revenues ($17 million) and increased equity in earnings ($1 million), partially offset by increased income tax expense ($27 million), decreased other income - net ($3 million) and increased interest expense, including interest expense to affiliated companies ($2 million).

Revenues

Revenues increased $17 million in the three months ended March 31, 2010, primarily due to:

- Increased retail sales volumes delivered ($25 million) due to increased consumption by residential customers, as a result of colder weather, and higher energy usage by industrial and commercial customers, as a result of improved economic conditions
- Increased DSM cost recovery ($4 million) due to increased recoverable program spending
- Increased miscellaneous revenue ($4 million) primarily resulting from the assessment of late payment fees beginning in the second quarter of 2009
- Increased ECR surcharge ($1 million) due to increased recoverable capital spending
- Decreased merger surcredit ($1 million) due to the surcredit termination resulting from the base rate settlement during February 2009

Partially offset by:

- Decreased fuel costs billed to customers through the FAC ($14 million) due to lower fuel prices
- Decreased wholesale sales ($4 million) due to:
    - Lower sales volumes to LG&E ($2 million) as a result of increased native load requirements in the first quarter of 2010 and coal-fired generation unit outages during the first quarter of 2010. Via a mutual agreement, KU sells its higher cost electricity to LG&E for its wholesale sales and KU purchases LG&E's lower cost electricity to serve its native load.
    - Decreased gains in energy marketing financial swaps ($2 million)
- Decreased revenues from base rates ($1 million) due to lower base energy non-fuel rates charged to customers during the period

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 $11 million in the three months ended March 31, 2010, primarily due to:

- Increased volumes of fuel usage ($22 million) due to increased native load

Partially offset by:

- Decreased commodity and transportation costs for coal ($11 million)

Power purchased expense decreased $10 million in the three months ended March 31, 2010, primarily due to:

- Decreased purchases from LG&E due to lower volumes ($6 million) and lower prices ($1 million). Via a mutual agreement, KU purchases LG&E's lower cost electricity to serve KU's native load. LG&E provided lower volumes due to its increased coal-fired generation unit outages during the first quarter of 2010
- Decreased prices for purchases used to serve retail customers ($4 million) due to lower spot market pricing

Partially offset by:

- Increased third-party purchased volumes for native load ($1 million) primarily due to coal-fired generation unit outages

Other operation and maintenance expense decreased $53 million in the three months ended March 31, 2010, due to decreased maintenance expense ($54 million), partially offset by increased other operation expense ($1 million).

Maintenance expense decreased $54 million in the three months ended March 31, 2010, primarily due to:

- Decreased distribution expense ($47 million) due to higher tree trimming and maintenance of overhead lines and line transformers as a result of 2009 winter storm restoration
- Decreased steam expense ($5 million) due to increased scope of work for scheduled outages in 2009
- Decreased transmission expense ($3 million) due to higher maintenance of overhead conductors and devices resulting from 2009 winter storm restoration

Partially offset by:

- Increased administrative and general expense ($1 million) due to increased labor and system maintenance contracts resulting from completion of a significant in-house customer information system project, which was capitalized in the first quarter of 2009

Equity in earnings of EEI increased $1 million in the three months ended March 31, 2010 due to higher earnings resulting from increased market prices.

Other income – net decreased $3 million in the three months ended March 31, 2010, primarily due to:

- Decreased allowance for funds used during construction on ECR projects ($2 million) as a result of the discontinuance of its use for ECR projects in the FERC rate case
- Decreased $1 million due mainly to depreciation expense on joint-use assets related to TC2 purchased from LG&E and currently held for future use

Interest expense, including interest expense to affiliated companies, increased $2 million in the three months ended March 31, 2010, primarily due to interest on increased borrowings with affiliated companies.

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

	Three Months Ended March 31, 2010	Three Months Ended March 31, 2009
Statutory federal income tax rate	35.0 %	35.0 %
State income taxes, net of federal benefit	3.6	(6.5)
Qualified production activities deduction	(1.1)	(9.1)
Dividends received deduction related to EEI investment	-	(25.4)
Amortization of investment tax credits	-	(0.5)
Nondeductible life insurance	(0.1)	(2.6)
Excess deferred taxes on depreciation	(0.5)	(5.0)
Other differences	0.2	(2.6)
Effective income tax rate	37.1 %	(16.7)%

The effective income tax rate increased to a more historically normal level for the three months ended March 31, 2010, compared to the three months ended March 31, 2009, primarily due to increased pretax income. The effective rate for the three months ended March 31, 2010, was also impacted by the lack of EEI dividends in 2010 and, therefore, no related dividends received deduction. State income taxes, net of federal benefit were lower in the three months ended March 31, 2009, due to a coal credit recorded in 2009. The decreases in income tax benefits associated with the qualified production activities deduction, nondeductible life insurance and excess deferred taxes are directly attributable to the quarter over quarter increase in pretax income.

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. As of March 31, 2010, KU had a working capital deficiency of $197 million, primarily due to the terms of certain tax-exempt bonds which allow the investors to put the bonds back to the Company causing them to be classified as current portion of long-term debt. The Company has adequate liquidity facilities to repurchase any bonds put back to the Company. Working capital deficiencies can be funded through an intercompany money pool agreement or through bilateral lines of credit. See Note 6 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.

Operating Activities

Cash provided by operations for the three months ended March 31, 2010, was $44 million more than cash provided by operations for the three months ended March 31, 2009, and was primarily the result of increases in cash due to changes in:

- Earnings, net of non-cash items ($36 million)
- Environmental cost recovery ($34 million), due to the ECR review case and subsequent roll-in of surcharge amounts to base rates in the first quarter of 2010
- Accrued income taxes ($13 million) due to higher net income in 2010
- Materials and supplies ($6 million)
- Other current assets and liabilities ($2 million)
- Other ($1 million)

These increases were partially offset by decreases in cash due to changes in:

- Accounts payable ($23 million) primarily due to timing of payments and higher accruals for storm expenses in 2009
- Pension and postretirement funding ($13 million) due to timing of pension contributions
- Accounts receivable ($12 million) primarily due to timing on collection of accounts and colder weather in the first quarter of 2010

Investing Activities

The primary use of funds for investing activities continues to be for capital expenditures. Net cash used for investing activities decreased $21 million in the three months ended March 31, 2010, compared to 2009, primarily due to decreased capital expenditures of $71 million, partially offset by an increase in assets purchased from an affiliate of $48 million and changes in restricted cash from bonds issued in 2008 used to fund environmental equipment of $2 million. Restricted cash represents the escrowed proceeds of pollution control bonds, which are disbursed as qualifying costs are incurred.

Financing Activities

Net cash flows used for financing activities were $17 million and net cash flows provided by financing activities were $47 million in the three months ended March 31, 2010 and 2009, respectively, resulting in an increase in net cash used for financing activities of $64 million. The decrease in financing cash flows is due to decreased equity contributions from E.ON U.S. of $50 million and increased repayments of short-term borrowings from an affiliated company of $14 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, 2012, to total approximately $1.1 billion, consisting primarily of on-going construction related to generation assets totaling approximately $265 million, ash pond and landfill projects totaling approximately $260 million, on-going construction related to distribution assets totaling approximately $240 million, the Brown SCR totaling approximately $160 million, construction estimates for installation of FGDs on Ghent and Brown units totaling approximately $140 million, other projects totaling approximately $30 million, information technology projects totally approximately $30 million and construction of TC2 totaling approximately $20 million (including $5 million for environmental controls).

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. Credit market conditions can affect aspects of the availability, terms or methods in which the Company funds its capital 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. The Company 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 the Company at market-based rates. Fidelia also provides long-term intercompany funding to KU. See Notes 6 and 9 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 2009, 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 2011, allowing short-term borrowing of up to $400 million. As of March 31, 2010, KU has borrowed $28 million of this authorized amount. See Note 6 of Notes to Financial Statements.

The Company's debt ratings as of March 31, 2010, were:

	Moody's	S&P
Unenhanced 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. In connection with E.ON U.S.'s announcement that E.ON AG and E.ON US Investments Corp. had entered into a definitive agreement with PPL to sell to PPL all the equity interests of E.ON U.S., Moody's placed the debt ratings of the Company under review for possible downgrade. S&P affirmed the existing ratings of the Company. See Note 6 of Notes to Financial Statements for a discussion of 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

Management 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.

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, management has assessed the effectiveness of the Company's internal control over financial reporting as of December 31, 2009, using the criteria set forth by the Committee of Sponsoring Organizations of the Treadway Commission in *Internal Control – Integrated Framework*. Management has concluded that, as of December 31, 2009, the Company's internal control over financial reporting was effective based on those criteria. There have been no changes in the Company's internal control over financial reporting that occurred during the three months ended March 31, 2010, that has materially affected, or is reasonably likely to materially affect, the Company's internal control over financial reporting.

The effectiveness of the Company's internal control over financial reporting as of December 31, 2009, was audited by PricewaterhouseCoopers LLP, an independent accounting firm, as stated in its report which is included in the 2009 KU Annual Report.

Legal Proceedings

For a description of the significant legal proceedings, including, but not limited to, certain rates and regulatory, environmental, climate change and litigation matters, involving KU, reference is made to the information under the following captions of the Company's Annual Report for the year ended December 31, 2009: 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, 7 and 9 of this quarterly report. Except as described in this quarterly report, to date, the proceedings reported in the Company's Annual Report for the year ended December 31, 2009 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, the Company 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 the Company's financial position or results of operations.

KENTUCKY UTILITIES COMPANY
FINANCIAL STATEMENTS

JUNE 30, 2010

Kentucky Utilities Company

Condensed Financial Statements and Additional Information

(Unaudited)

As of June 30, 2010 and December 31, 2009
and for the three-month and six-month periods ended
June 30, 2010 and 2009

INDEX OF ABBREVIATIONS

AG	Attorney General of Kentucky
ARO	Asset Retirement Obligation
ASC	Accounting Standards Codification
BART	Best Available Retrofit Technology
CAIR	Clean Air Interstate Rule
CAMR	Clean Air Mercury Rule
CATR	Clean Air Transport Rule
CCN	Certificate of Public Convenience and Necessity
Clean Air Act	The Clean Air Act, as amended in 1990
CMRG	Carbon Management Research Group
Companies	KU and LG&E
Company	KU
DSM	Demand Side Management
ECR	Environmental Cost Recovery
EEI	Edison Electric Institute
EKPC	East Kentucky Power Cooperative, Inc.
E.ON	E.ON AG
E.ON U.S.	E.ON U.S. LLC
E.ON U.S. Services	E.ON U.S. 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)
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
LG&E	Louisville Gas and Electric Company
MISO	Midwest Independent Transmission System Operator, Inc.
MMBtu	Million British thermal units
Moody's	Moody's Investors Service, Inc.
Mw	Megawatts
Mwh	Megawatt hours
NAAQS	National Ambient Air Quality Standards
NOV	Notice of Violation
NOx	Nitrogen Oxide
OMU	Owensboro Municipal Utilities
PPL	PPL Corporation
S&P	Standard & Poor's Ratings Services
SCR	Selective Catalytic Reduction
SERC	SERC Reliability Corporation
SIP	State Implementation Plan
SO_2	Sulfur Dioxide
TC1	Trimble County Unit 1
TC2	Trimble County Unit 2
Virginia Commission	Virginia State Corporation Commission

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PRICEWATERHOUSECOOPERS

PricewaterhouseCoopers LLP
500 West Main Street
Suite 1800
Louisville KY 40202-4264
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Report of Independent Accountants

To Shareholder of Kentucky Utilities Company:

We have reviewed the accompanying condensed balance sheet of Kentucky Utilities Company as of June 30, 2010, and the related condensed statements of income and retained earnings for the three-month and six-month periods ended June 30, 2010 and 2009 and the condensed statement of cash flows for the six-month periods ended June 30, 2010 and 2009. This condensed interim financial information is the responsibility of the Company's management.

We conducted our review in accordance with standards established by the American Institute of Certified Public Accountants. A review of interim financial information consists principally of applying analytical procedures and making inquiries of persons responsible for financial and accounting matters. It is substantially less in scope than an audit conducted in accordance with auditing standards generally accepted in the United States of America, the objective of which is the expression of an opinion regarding the financial information taken as a whole. Accordingly, we do not express such an opinion.

Based on our review, we are not aware of any material modifications that should be made to the accompanying condensed interim financial information for it to be in conformity with accounting principles generally accepted in the United States of America.

We have previously audited, in accordance with auditing standards generally accepted in the United States of America, the balance sheet of Kentucky Utilities Company as of December 31, 2009, and the related statements of income, retained earnings, and of cash flows for the year then ended (not presented herein), and in our report dated March 19, 2010, we expressed an unqualified opinion on those financial statements. In our opinion, the information set forth in the accompanying condensed balance sheet information as of December 31, 2009, is fairly stated in all material respects in relation to the balance sheet from which it has been derived.

PricewaterhouseCoopers LLP

August 11, 2010

Kentucky Utilities Company
Condensed Statements of Income
(Unaudited)
(Millions of $)

	Three Months Ended June 30, 2010	Three Months Ended June 30, 2009	Six Months Ended June 30, 2010	Six Months Ended June 30, 2009
Operating revenues				
Total operating revenues (Note 8)	$ 350	$ 305	$ 730	$ 668
Operating expenses				
Fuel for electric generation	119	100	245	215
Power purchased (Note 8)	40	43	94	107
Other operation and maintenance expenses	86	76	165	208
Depreciation and amortization	34	33	68	66
Total operating expenses	279	252	572	596
Operating income	71	53	158	72
Equity in loss (earnings) of unconsolidated venture	1	1	(2)	(1)
Other expense (income) – net (Note 3)	1	(3)	1	(6)
Interest expense (Note 6)	1	1	3	3
Interest expense to affiliated companies (Notes 6 and 8)	19	17	37	33
Income before income taxes	49	37	119	43
Income tax expense (Note 5)	18	11	44	10
Net income	$ 31	$ 26	$ 75	$ 33

The accompanying notes are an integral part of these condensed financial statements.

Condensed Statements of Retained Earnings
(Unaudited)
(Millions of $)

	Three Months Ended June 30, 2010	Three Months Ended June 30, 2009	Six Months Ended June 30, 2010	Six Months Ended June 30, 2009
Balance at beginning of period	$ 1,372	$ 1,202	$ 1,328	$ 1,195
Net income	31	26	75	33
Balance at end of period	$ 1,403	$ 1,228	$ 1,403	$ 1,228

The accompanying notes are an integral part of these condensed financial statements.

Kentucky Utilities Company
Condensed Balance Sheets
(Unaudited)
(Millions of $)

Assets	June 30, 2010	December 31, 2009
Current assets:		
Cash and cash equivalents	$ 3	$ 2
Accounts receivable, net:		
Customer – less reserves of $2 million and $1 million as of June 30, 2010 and December 31, 2009, respectively	165	155
Other – less reserves of $2 million as of June 30, 2010 and December 31, 2009, respectively	17	18
Accounts receivable from affiliated companies	-	9
Materials and supplies:		
Fuel (predominantly coal)	113	98
Other materials and supplies	41	39
Income tax receivable	15	-
Deferred income taxes – net (Note 5)	3	3
Regulatory assets (Note 2)	13	32
Prepayments and other current assets	5	10
Total current assets	375	366
Other property and investments	14	12
Utility plant:		
At original cost	5,306	4,892
Less: reserve for depreciation	1,872	1,838
Total utility plant, net	3,434	3,054
Construction work in progress	971	1,257
Net utility plant and construction work in progress	4,405	4,311
Deferred debits and other assets:		
Regulatory assets (Note 2):		
Pension and postretirement benefits	105	105
Other	119	117
Cash surrender value of key man life insurance	38	38
Other assets	7	7
Total deferred debits and other assets	269	267
Total assets	$ 5,063	$ 4,956

The accompanying notes are an integral part of these condensed financial statements.

Kentucky Utilities Company
Condensed Balance Sheets (cont.)
(Unaudited)
(Millions of $)

Liabilities and Equity	June 30, 2010	December 31, 2009
Current liabilities:		
Current portion of long-term bonds (Notes 3 and 6)	$ 228	$ 228
Current portion of long-term debt to affiliated company (Note 3)	33	33
Notes payable to affiliated companies (Notes 6 and 8)	84	45
Accounts payable	95	107
Accounts payable to affiliated companies (Note 8)	66	88
Accrued income taxes	-	5
Customer deposits	22	22
Regulatory liabilities (Note 2)	5	3
Other current liabilities	31	37
Total current liabilities	564	568
Long-term debt:		
Long-term bonds (Notes 3 and 6)	123	123
Long-term debt to affiliated company (Notes 3, 6 and 8)	1,298	1,298
Total long-term debt	1,421	1,421
Deferred credits and other liabilities:		
Accumulated deferred income taxes (Note 5)	366	336
Accumulated provision for pensions and related benefits (Note 4)	156	160
Investment tax credit (Note 5)	104	104
Asset retirement obligations	35	34
Regulatory liabilities (Note 2):		
Accumulated cost of removal of utility plant	340	331
Deferred income taxes - net	10	9
Postretirement benefits	9	9
MISO exit	3	4
Other	8	7
Customer advances for construction	3	3
Other liabilities	17	18
Total deferred credits and other liabilities	1,051	1,015
Common equity:		
Common stock, without par value - Authorized 80,000,000 shares, outstanding 37,817,878 shares	308	308
Additional paid-in capital (Note 8)	316	316
Retained earnings	1,392	1,318
Undistributed subsidiary earnings	11	10
Total retained earnings	1,403	1,328
Total common equity	2,027	1,952
Total liabilities and equity	$ 5,063	$ 4,956

The accompanying notes are an integral part of these condensed financial statements.

Kentucky Utilities Company
Condensed Statements of Cash Flows
(Unaudited)
(Millions of $)

	For the Six Months Ended June 30, 2010	2009
Cash flows from operating activities:		
Net income	$ 75	$ 33
Items not requiring cash currently:		
Depreciation and amortization	68	66
Deferred income taxes – net	29	6
Investment tax credit – net	-	11
Provision for pension and post retirement plans	7	9
Undistributed earnings of unconsolidated venture	(2)	9
Other	-	(2)
Changes in current assets and liabilities:		
Accounts receivable	-	18
Materials and supplies	(17)	(28)
Income tax receivable	(15)	-
Environmental cost recovery	29	(11)
Fuel adjustment clause	(8)	3
Accounts payable	11	(5)
Accrued income taxes	(5)	-
Other current assets and liabilities	-	5
Pension and postretirement funding (Note 4)	(16)	(16)
Other	(1)	(4)
Net cash provided by operating activities	155	94
Cash flows from investing activities:		
Construction expenditures	(145)	(271)
Assets purchased from affiliate	(48)	-
Change in restricted cash	-	9
Net cash used for investing activities	(193)	(262)
Cash flows from financing activities:		
Short-term borrowings from affiliated company – net (Note 6)	39	44
Long-term borrowings from affiliated company (Note 6)	-	50
Capital contribution (Note 9)	-	75
Net cash provided by financing activities	39	169
Change in cash and cash equivalents	1	1
Cash and cash equivalents at beginning of period	2	2
Cash and cash equivalents at end of period	$ 3	$ 3

The accompanying notes are an integral part of these condensed financial statements.

Kentucky Utilities Company
Notes to Condensed Financial Statements
(Unaudited)

Note 1 - General

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 condensed financial statements include all adjustments, consisting only of normal recurring adjustments, necessary for fair statements of income and retained earnings, balance sheets, and statements of 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 condensed financial statements and notes should be read in conjunction with the Company's Financial Statements and Additional Information ("Annual Report") for the year ended December 31, 2009, including the audited financial statements and notes therein. The December 31, 2009 Condensed Balance Sheet included herein is derived from the December 31, 2009 audited balance sheet. Amounts reported in the Condensed Statements of Income are not necessarily indicative of amounts expected for the respective annual periods due to the effects of seasonal temperature variations on energy consumption, regulatory rulings, the timing of maintenance on electric generating units, changes in mark-to-market valuations, changing commodity prices and other factors.

Certain reclassification entries have been made to the previous years' financial statements to conform to the 2010 presentation with no impact on net assets, liabilities and capitalization or previously reported net income and net cash flows. However, cash flows provided by operating activities decreased by $2 million and cash flows used for investing activities decreased by $2 million.

PPL Acquisition

On April 28, 2010, E.ON U.S. announced that a Purchase and Sale Agreement (the "Agreement") had been entered into among E.ON US Investments, PPL and E.ON.

The Agreement provides for the sale of E.ON U.S. to PPL. Pursuant to the Agreement, at closing, PPL will acquire all of the outstanding limited liability company interests of E.ON U.S. for cash consideration of $2.1 billion. In addition, pursuant to the Agreement, PPL agreed to assume $925 million of pollution control bonds and to repay indebtedness owed by E.ON U.S. and its subsidiaries to E.ON US Investments and its affiliates. Such affiliate indebtedness is currently estimated to be $4.6 billion. The aggregate consideration payable by PPL on closing, $7.6 billion (including the assumed indebtedness), is subject to adjustment for specified incremental investment in E.ON U.S. that will potentially be made by E.ON US Investments and its affiliates prior to closing.

The transaction is subject to customary closing conditions, including the expiration or termination of the applicable waiting period under the Hart-Scott-Rodino Act, receipt of required regulatory approvals (including state regulators in Kentucky, Virginia and Tennessee, and the FERC) and the absence of injunctions or restraints imposed by governmental entities. Subject to receipt of required approvals, the transaction is expected to close by the end of 2010. Change of control and financing-related applications were filed on May 28, 2010, with the Kentucky

Commission and on June 15, 2010, with the Virginia Commission and the Tennessee Regulatory Authority. An application with the FERC was filed on June 28, 2010. During the second quarter of 2010, a number of parties were granted intervenor status in the Kentucky Commission proceedings and data request filings and responses occurred. Hearings in the Kentucky Commission proceedings are scheduled for September 8, 2010. Early termination of the final Hart-Scott-Rodino waiting period was received on August 2, 2010.

Based upon credit and financial market conditions, the anticipated PPL acquisition and other factors, the Company anticipates completing certain re-financing transactions and, where applicable, has applied for regulatory approvals for such transactions. KU anticipates issuing up to $1.6 billion in public first mortgage bonds, the proceeds of which will substantially be used to refund existing long-term intercompany debt. As required by existing covenants, in connection with the issuance of any such secured debt, KU would also collateralize certain outstanding pollution control bond debt series which are presently unsecured. Upon such collateralization, approximately $351 million in existing pollution control debt would become secured debt, supported by a first mortgage lien. Subject to regulatory approvals and other conditions, KU may complete these transactions, in whole or in part, during late 2010 and early 2011.

Recent Accounting Pronouncements

Fair Value Measurements

In January 2010, the FASB issued guidance related to fair value measurement disclosures requiring separate disclosure of amounts of significant transfers in and out of level 1 and level 2 fair value measurements and separate information about purchases, sales, issuances, and settlements within level 3 measurements. This guidance is effective for the interim and annual reporting periods beginning after December 15, 2009, except for the disclosures about the roll-forward of activity in level 3 fair value measurements. Those disclosures are effective for fiscal years beginning after December 15, 2010, and for interim periods within those fiscal years. This guidance has no impact on the Company's results of operations, financial position, liquidity or disclosures.

Note 2 - Rates and Regulatory Matters

For a description of each line item of regulatory assets and liabilities and for descriptions of certain matters which may not have undergone material changes relating to the period covered by this quarterly report, reference is made to Note 2 of KU's Annual Report for the year ended December 31, 2009.

2010 Kentucky Rate Case

In January 2010, KU filed an application with the Kentucky Commission requesting an increase in electric base rates of approximately 12%, or $135 million annually, including an 11.5% return on equity. KU requested the increase, based on the twelve month test year ended October 31, 2009, to become effective on and after March 1, 2010. The requested rates were suspended until August 1, 2010. A number of intervenors entered the rate case, including the Kentucky Attorney General's office, certain representatives of industrial and low-income groups and other third parties, and submitted filings challenging the Company's requested rate increases, in whole or in part. A hearing was held on June 8, 2010. KU and all of the intervenors except the AG agreed to a stipulation providing for an increase in electric base rates of $98 million annually and filed a request with the Kentucky Commission to approve such settlement. An Order in the proceeding was issued in July 2010, approving all the provisions in the stipulation, with rates effective on and after August 1, 2010.

Virginia Rate Case

In June 2009, KU filed an application with the Virginia Commission requesting an increase in electric base rates for its Virginia jurisdictional customers in an amount of $12 million annually or approximately 21%. The proposed increase reflected a proposed rate of return on rate base of 8.586% based upon a return on equity of 12%. During December 2009, KU and the Virginia Commission Staff agreed to a Stipulation and Recommendation authorizing base rate revenue increases of $11 million annually and a return on rate base of 7.846% based on a 10.5% return on common equity. A public hearing was held during January 2010. As permitted, pursuant to a Virginia Commission Order, KU elected to implement the proposed rates effective November 1, 2009, on an interim basis. In March 2010, the Virginia Commission issued an Order approving the stipulation, with the increased rates to be put into effect as of April 1, 2010. As part of the stipulation, KU refunded certain amounts collected since November 2009, consisting of interim rates in excess of the ultimate approved rates. These refunds, including interest, aggregated approximately $1 million and were made during May and June 2010. During the third quarter of 2010, a report is expected to be filed detailing the costs of the refunds, the accounts charged and details validating that all refunds have been made.

FERC Wholesale Rate Case

In September 2008, KU filed an application with the FERC for increases in electric base rates applicable to wholesale power sales contracts or interchange agreements involving, collectively, twelve Kentucky municipalities. The application requested a shift from current, all-in stated unit charge rates to an unbundled formula rate, including an annual adjustment mechanism. In May 2009, the FERC issued an Order approving a settlement among the parties in the case, incorporating increases of approximately 3% from prior rates and a return on equity of 11%. In May 2010, KU submitted to the FERC the proposed current annual adjustment to the formula rate. This updated rate became effective on July 1, 2010, subject to certain review procedures by the wholesale requirements customers and the FERC, including potential refunds in the case of disallowed costs or charges.

By mutual agreement, the parties' settlement of the 2008 application left outstanding the issue of whether KU must allocate to the municipal customers a portion of renewable resources it may be required to procure on behalf of its retail ratepayers. In August 2009, the FERC accepted the issue for briefing and the parties completed briefing submissions during 2009. An Order was issued by the FERC in July 2010, indicating that KU is not required to allocate a portion of any renewable resources to the twelve municipalities, thus resolving the remaining issue.

Regulatory Assets and Liabilities

The following regulatory assets and liabilities were included in KU's Balance Sheets:

(in millions)	June 30, 2010	December 31, 2009
Current regulatory assets:		
ECR	$ -	$ 28
FAC	9	1
MISO exit	2	2
Other	2	1
Total current regulatory assets	$ 13	$ 32
Non-current regulatory assets:		
Storm restoration	$ 59	$ 59
ARO	31	30
Unamortized loss on bonds	12	12
MISO exit	8	9
Other	9	7
Subtotal non-current regulatory assets	119	117
Pension benefits	105	105
Total non-current regulatory assets	$ 224	$ 222
Current regulatory liabilities:		
DSM	$ 3	$ 3
ECR	1	-
MISO exit	1	-
Total current regulatory liabilities	$ 5	$ 3
Non-current regulatory liabilities:		
Accumulated cost of removal of utility plant	$ 340	$ 331
Deferred income taxes – net	10	9
Postretirement benefits	9	9
MISO exit	3	4
Other	8	7
Total non-current regulatory liabilities	$ 370	$ 360

KU does not currently earn a rate of return on the ECR and FAC regulatory assets and the Virginia levelized fuel factor included in other non-current regulatory liabilities, which are separate recovery mechanisms with recovery within twelve months. No return is earned on the pension benefits regulatory asset that represents the changes in funded status of the plans. KU will recover this asset through 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. When an asset with an ARO is retired, the related ARO regulatory asset will be offset against the associated ARO regulatory liability, ARO asset and ARO liability. ARO liabilities are included in other non-current regulatory liabilities. A return is earned on the unamortized loss on bonds, including the portion in other current regulatory assets, and these costs are recovered through amortization over the life of the debt. The Company received approval in its current base rate case to recover the storm restoration regulatory asset over a ten year period. The Company also received approval for adjustments to the amortization of CMRG and KCCS contributions, included in other non-current regulatory assets. The Company recovers through the calculation of base rates, the amortization of the net MISO exit regulatory asset in Kentucky incurred through April 30, 2008. The Company received approval to recover the Virginia portion of this asset, as incurred through December 31, 2008, over a five year period and, due to the formula nature of its FERC rate structure, the FERC jurisdictional portion of the regulatory asset will be included in the annual updates to the rate formula. Recovery of the FERC jurisdictional pension expense, included in other non-current regulatory assets, and the change in accounting method for spare parts, included in other non-current regulatory liabilities, will be requested in the next FERC rate case. The Company recovers through the calculation of base rates, the amortization of the remaining regulatory assets, other current and non-current regulatory assets comprised of the East Kentucky Power Cooperative FERC transmission settlement agreement and Kentucky rate case expenses. The regulatory liabilities for the MISO exit include administrative charges collected via base rates from May 2008 through February 5, 2009, and refunds of the exit fee. The MISO regulatory liability will be netted against the remaining costs of withdrawing from the MISO, except for a small portion of the refund attributable to Kentucky customers which occurred in 2010 and which will be addressed in a later rate case, per a Kentucky Commission Order, in the current Kentucky base rate case. Refunds from the MISO for a portion of the cost of exiting will also be netted against the remaining balances of these costs in the current Kentucky base rate case, as well as in future Kentucky base rate cases, in future Virginia base rate cases and also included in the calculation of future FERC formula-based rates.

ECR. In July 2010, the Kentucky Commission initiated a six-month review of KU's environmental surcharge for the billing period ending April 2010. An order is expected in the fourth quarter of 2010.

In January 2010, the Kentucky Commission initiated a six-month review of KU's environmental surcharge for the billing period ending October 2009. In May 2010, an Order was issued approving the amounts billed through the ECR during the six-month period and the rate of return on capital and allowing recovery of the under-recovery position in subsequent monthly filings.

In June 2009, the Company filed an application for a new ECR plan with the Kentucky Commission seeking approval to recover investments in environmental upgrades and operations and maintenance costs at the Company's generating facilities. During 2009, KU reached a unanimous settlement with all parties to the case, and the Kentucky Commission issued an Order approving KU's application. Recovery on customer bills through the monthly ECR surcharge for these projects began with the February 2010 billing cycle. At December 31, 2009, the Company had a regulatory asset of $28 million, which changed to a regulatory liability in the first quarter of 2010, as a result of these roll-in adjustments to base rates. At June 30, 2010, the regulatory liability balance is $1 million.

FAC. In February 2010, KU filed an application with the Virginia Commission seeking approval of a decrease in its fuel cost factor beginning with service rendered in April 2010. In February 2010, the Virginia Commission recommended a change to the fuel factor KU had in its application, to which KU agreed. Following a public hearing in March 2010, and an Order in

April 2010, the recommended charge became effective as of April 1, 2010, resulting in a decrease of 23% from the fuel factor in effect for April 2009 through March 2010.

In January 2010, the Kentucky Commission initiated a six-month review of KU's FAC mechanism for the expense period ended August 2009. In May 2010, an Order was issued approving the charges and credits billed through the FAC during the review period.

Storm Restoration. In January 2009, a significant ice storm passed through KU's service territory causing approximately 199,000 customer outages and was followed closely by a severe wind storm in February 2009 that caused approximately 44,000 customer outages. KU incurred \$57 million in incremental operation and maintenance expenses and \$33 million in capital expenditures related to the restoration following the two storms. The Company filed an application with the Kentucky Commission in April 2009, requesting approval to establish a regulatory asset and defer for future recovery approximately \$62 million in incremental operation and maintenance expenses related to the storm restoration. In September 2009, the Kentucky Commission issued an Order allowing the Company to establish a regulatory asset of up to \$62 million based on its actual costs for storm damages and service restoration due to the January and February 2009, storms. In September 2009, the Company established a regulatory asset of \$57 million for actual costs incurred. The Company received approval in its current base rate case to recover this asset over a ten year period beginning August 1, 2010.

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. In December 2008, the Company established a regulatory asset of \$2 million for actual costs incurred. The Company received approval in its current base rate case to recover this asset over a ten year period beginning August 1, 2010.

<u>Other Regulatory Matters</u>

Wind Power Agreements. In September 2009, the Companies filed an application and supporting testimony with the Kentucky Commission for approval of wind power purchase contracts and cost recovery mechanisms, under which KU and LG&E would jointly purchase respective assigned portions of the output of two Illinois wind farms totaling an aggregate 109.5 Mw. In October 2009, the Kentucky Commission issued an Order denying the Companies' request to establish a surcharge for recovery of the costs of purchasing wind power. In March 2010, KU and LG&E delivered notices of termination under provisions of the wind power contracts. The Companies also filed a motion with the Kentucky Commission noting the termination of the contracts and seeking withdrawal of their application in the related regulatory proceeding. In April 2010, the Kentucky Commission issued an Order allowing the Companies to withdraw their pending application.

TC2 Depreciation. In August 2009, KU and LG&E jointly filed an application with the Kentucky Commission to approve new common depreciation rates for applicable jointly-owned TC2-related generating, pollution control and other plant equipment and assets. During

December 2009, the Kentucky Commission extended the data discovery process through January 2010, and authorized KU and LG&E on an interim basis to begin using the depreciation rates for TC2 as proposed in the application. In March 2010, the Kentucky Commission issued a final Order approving the use of the proposed depreciation rates on a permanent basis.

TC2 Transmission Matters. KU's and LG&E's CCN for a transmission line associated with the TC2 construction has been challenged by certain property owners in Hardin County, Kentucky. In August 2006, KU and LG&E obtained a successful dismissal of the challenge at the Franklin County Circuit Court, which was reversed by the Kentucky Court of Appeals in December 2007. In April 2009, the Kentucky Supreme Court granted KU's and LG&E's motion for discretionary review of the Court of Appeal's decision. KU's and LG&E's proceeding before the Kentucky Supreme Court, which seeks reinstatement of the Circuit Court dismissal of the CCN challenge, has been fully briefed and oral argument occurred during March 2010. A ruling on the matter could occur during the second half of 2010.

During 2008, KU obtained various successful rulings at the Hardin County Circuit Court confirming its condemnation rights. In August 2008, several landowners appealed such rulings to the Kentucky Court of Appeals. In May 2010, the Kentucky Court of Appeals issued an Order affirming the Hardin Circuit Court's finding that KU had the right to condemn easements on the properties. In May 2010, the landowners filed a petition for reconsideration with the Court of Appeals. In July 2010, the Court of Appeals denied that petition. The landowners may seek discretionary review of that denial by the Kentucky Supreme Court on or before August 21, 2010.

As a result of the aforementioned proceedings delaying access to certain properties in Hardin County, KU obtained easements to allow construction of temporary transmission facilities for approximately ten years, which bypass the disputed properties while the litigated issues are resolved. In December 2009, the Kentucky Commission granted CCNs for the relevant temporary segments. In January 2010, the Franklin County Circuit Court issued Orders denying the property owners' request for a stay of construction and upholding the Kentucky Commission's denial of their intervenor status.

In a separate proceeding, certain Hardin County landowners have filed an action in federal district court in Louisville, Kentucky against the U.S. Army challenging the same transmission line claiming that certain Fort Knox-related sections of the line failed to comply with certain National Historic Preservation Act procedural requirements. In October 2009, the federal court granted the defendants' motion for summary judgment and dismissed the plaintiffs' claims. During November 2009, the petitioners filed submissions for review of the decision with the 6th Circuit Court of Appeals. That appeal has since been voluntarily withdrawn by the plaintiffs.

Consistent with the regulatory authorizations and relevant legal proceedings, the Company has completed construction activities on temporary or permanent transmission line segments, respectively. During the second quarter of 2010, KU and LG&E placed into operation an appropriate combination of permanent and temporary sections of the transmission line. While KU and LG&E are not currently able to predict the ultimate outcome and possible financial effects of the remaining legal proceedings, KU and LG&E do not believe the matter involves relevant or continuing risks to operations.

KU and LG&E are not currently able to predict the ultimate outcome and possible effects, if any, on the construction schedule relating to the permanent transmission line approval, land acquisition and permitting proceedings.

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 Regional Reliability Organizations ("RROs") by the North American Electric Reliability Corporation ("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 and LG&E are members of the SERC, which acts as KU's and LG&E's RRO. During December 2009, the SERC and KU and LG&E agreed to settlements involving penalties totaling less than $1 million for each utility related to their self-reports during June and October 2008, concerning possible violations of standards. During December 2009 and April and July 2010, KU and LG&E submitted four self-reports relating to various standards, which self-reports remain in the early stages of RRO review, and therefore, the Companies are unable to estimate the outcome of these matters. Mandatory reliability standard settlements commonly also include non-penalty elements, including compliance steps and mitigation plans. Settlements with the SERC proceed to NERC and FERC review before becoming final. While KU and LG&E believe they are in compliance with the mandatory reliability standards, other events of potential non-compliance may be identified from time-to-time. The Companies cannot predict such potential violations or the outcomes of the self-reports described above.

Note 3 - *Financial Instruments*

The cost and estimated fair values of KU's non-trading financial instruments as of June 30, 2010 and December 31, 2009 follow:

	June 30, 2010		December 31, 2009	
(in millions)	Carrying Value	Fair Value	Carrying Value	Fair Value
Long-term bonds (including current portion of $228 million)	$ 351	$ 351	$ 351	$ 351
Long-term debt to affiliated company (including current portion of $33 million)	1,331	1,482	1,331	1,401

The long-term debt valuations reflect prices quoted by dealers. The fair value of the long-term debt to affiliated company 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 interest rate and commodity price risk related to on-going business operations. It currently manages these risks using derivative financial instruments, including swaps and forward contracts. The Company'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 June 30, 2010, a 100 basis point change in the benchmark rate on KU's variable rate debt, not effectively hedged by an interest rate swap, would impact pre-tax interest expense by $4 million annually. Although the Company's policies allow for the use of interest rate swaps, as of June 30, 2010 and December 31, 2009, KU had no interest rate swaps outstanding.

KU has classified the applicable financial assets and liabilities that are accounted for at fair value into the three levels of the fair value hierarchy, as defined by the fair value measurements and disclosures topic of the FASB ASC, as follows:

- Level 1 - Observable inputs that reflect quoted prices (unadjusted) for identical assets or liabilities in active markets.
- Level 2 - Include other inputs that are directly or indirectly observable in the marketplace.
- Level 3 - Unobservable inputs which are supported by little or no market activity.

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 the derivatives and hedging topic of the FASB ASC.

Energy trading and risk management contracts are valued using prices based on active trades from Intercontinental Exchange Inc. In the absence of a traded price, midpoints of the best bids and offers are the primary determinants of valuation. When sufficient trading activity is unavailable, other inputs 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 measurement criteria in the fair value measurements and disclosures topic of the FASB ASC. 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 2010 or 2009. Changes in market pricing, interest rate and volatility assumptions were made during both years.

The Company maintains credit policies intended to minimize credit risk in wholesale marketing and trading activities by assessing the creditworthiness of potential counterparties prior to entering into transactions with them and continuing to evaluate their creditworthiness once transactions have been initiated. To further mitigate credit risk, KU seeks to enter into netting agreements or require cash deposits, letters of credit and parental company guarantees as security from counterparties. The Company uses S&P, Moody's and definitive qualitative and quantitative data to assess the financial strength of counterparties on an on-going basis. If no external rating exists, KU assigns an internally generated rating for which it sets appropriate risk parameters. As risk management contracts are valued based on changes in market prices of the related commodities, credit exposures are revalued and monitored on a daily basis.
At June 30, 2010, 100% of the trading and risk management commitments were with counterparties rated BBB-/Baa3 equivalent or better. The Company 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 June 30, 2010 and December 31, 2009, counterparty credit reserves related to energy trading and risk management contracts were less than $1 million.

The net volume of electricity based financial derivatives outstanding at June 30, 2010 and December 31, 2009, was zero Mwhs and 43,400 Mwhs, respectively. No cash collateral related to the energy trading and risk management contracts was required at June 30, 2010. Cash collateral related to the energy trading and risk management contracts was less than $1 million at December 31, 2009. Cash collateral related to the energy trading and risk management contracts is categorized as other accounts receivable and is a level 1 measurement based on the criteria previously defined.

KU's financial assets and liabilities as of June 30, 2010 and December 31, 2009, arising from energy trading and risk management contracts accounted for at fair value total less than $1 million and use level 2 measurements. There are no level 1 or level 3 measurements for the periods ending June 30, 2010 and December 31, 2009.

The Company does not net collateral against derivative instruments.

Certain of the Company's derivative instruments contain provisions that require the Company to provide immediate and on-going collateralization on derivative instruments in net liability positions based upon the Company's credit ratings from each of the major credit rating agencies. At June 30, 2010, there are no energy trading and risk management contracts with credit risk related contingent features that are in a liability position and no collateral posted in the normal course of business. At June 30, 2010, a one notch downgrade of the Company's credit rating would have no effect on the energy trading and risk management contracts or collateral required.

At June 30, 2010 and December 31, 2009, the fair value of short-term assets and liabilities for energy trading and risk management contracts not designated as hedging instruments was less than $1 million and was recorded in other current assets and other current liabilities, respectively.

KU manages the price risk of its estimated future excess economic generation capacity using market-traded forward contracts. Hedge accounting treatment has not been elected for these transactions, and therefore gains and losses are shown in the statements of income.

The following table presents the effect of derivatives not designated as hedging instruments on income for the six months ended June 30, 2009:

(in millions)	Location of (Gain) Loss Recognized in Income on Derivatives	Amount of (Gain) Loss Recognized in Income on Derivatives
Energy trading and risk management contracts (unrealized)	Electric revenues	$ (2)

Net unrealized losses were less than $1 million in the three-month periods ended June 30, 2010 and 2009, respectively, and net unrealized gains were less than $1 million in the six-month period ended June 30, 2010. Net realized gains were less than $1 million in the three and six month periods ended June 30, 2010 and 2009, respectively.

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 for the three and six months ended June 30. The tables include the costs associated with both KU employees and E.ON U.S. Services employees who are providing services to the Company. The E.ON U.S. Services costs that are allocated to KU are approximately 53% and 51% of E.ON U.S. Services costs for June 30, 2010 and 2009, respectively.

(in millions)	Pension Benefits Three Months Ended June 30, 2010			2009		
	KU	E.ON U.S. Services Allocation to KU	Total KU	KU	E.ON U.S. Services Allocation to KU	Total KU
Service cost	$ 1	$ 2	$ 3	$ 2	$ 1	$ 3
Interest cost	5	2	7	4	2	6
Expected return on plan assets	(4)	(2)	(6)	(3)	(1)	(4)
Amortization of actuarial loss	2	-	2	2	1	3
Benefit cost	$ 4	$ 2	$ 6	$ 5	$ 3	$ 8

(in millions)	Other Postretirement Benefits Three Months Ended June 30, 2010			2009		
	KU	E.ON U.S. Services Allocation to KU	Total KU	KU	E.ON U.S. Services Allocation to KU (a)	Total KU
Service cost	$ -	$ 1	$ 1	$ -	$ -	$ -
Interest cost	1	-	1	1	-	1
Expected return on plan assets	(1)	-	(1)	-	-	-
Amortization of transitional	1	-	1	-	-	-
Benefit cost	$ 1	$ 1	$ 2	$ 1	$ -	$ 1

(a) amounts are less than $1 million

(in millions)	Pension Benefits Six Months Ended June 30,					
	2010			2009		
	KU	E.ON U.S. Services Allocation to KU	Total KU	KU	E.ON U.S. Services Allocation to KU	Total KU
Service cost	$ 3	$ 3	$ 6	$ 3	$ 3	$ 6
Interest cost	10	4	14	9	4	13
Expected return on plan assets	(8)	(3)	(11)	(7)	(3)	(10)
Amortization of prior service costs	-	-	-	-	1	1
Amortization of actuarial loss	3	1	4	5	1	6
Benefit cost	$ 8	$ 5	$ 13	$ 10	$ 6	$ 16

(in millions)	Other Postretirement Benefits Six Months Ended June 30,					
	2010			2009		
	KU	E.ON U.S. Services Allocation to KU	Total KU	KU	E.ON U.S. Services Allocation to KU	Total KU
Service cost	$ 1	$ 1	$ 2	$ 1	$ 1	$ 2
Interest cost	2	-	2	2	-	2
Expected return on plan assets	(1)	-	(1)	(1)	-	(1)
Amortization of transitional	1	-	1	1	-	1
Benefit cost	$ 3	$ 1	$ 4	$ 3	$ 1	$ 4

In January 2010, KU and E.ON U.S. Services made a pension plan contribution of $13 million and $9 million, respectively. KU's intent is to fund the pension plan in a manner consistent with the requirements of the Pension Protection Act of 2006.

In 2010, KU has made contributions to other postretirement benefit plans totaling $3 million. The Company also anticipates further funding to match the annual postretirement expense and funding the 401(h) plan up to the maximum amount allowed by law.

Health Care Reform

In March 2010, Health Care Reform (the Patient Protection and Affordable Care Act of 2010) was signed into law. Many provisions of Health Care Reform do not take effect for an extended period of time, and many aspects of the law which are currently unclear or undefined will likely be clarified in future regulations.

During each of the three and six month periods ended June 30, 2010, KU recorded an income tax expense of less than $1 million, to recognize the impact of the elimination effective in 2013 of the tax deduction related to the Medicare Retiree Drug Subsidy.

Specific provisions within Health Care Reform that may impact KU include:

- Beginning in 2011, a requirement to extend dependent coverage up to age 26.
- Beginning in 2018, a potential excise tax on high-cost plans providing health coverage that exceeds certain thresholds.

KU continues to evaluate all implications of Health Care Reform on its benefit programs but at this time cannot predict the significance of those implications.

Note 5 - 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. The Company also files income tax returns in various state jurisdictions. While 2006 and later years are open under the federal statute of limitations, Revenue Agent Reports for 2006-2008 have been received from the IRS, effectively closing these years to additional audit adjustments. Tax years 2007 and 2008 were examined under an IRS pilot program named "Compliance Assurance Process" ("CAP"). This program accelerates the IRS' review to begin during the year applicable to the return and ends 90 days after the return is filed. For 2008, the IRS allowed additional deductions in connection with the Company's application for a change in repair deductions and disallowed some of the bonus depreciation claimed on the original return. The net temporary tax impact for the Company was $12 million, and has been recorded in the second quarter of 2010. Tax years 2009 and 2010 are also being examined under CAP. No material items have been raised by the IRS at this time.

Additions and reductions of uncertain tax positions during 2010 and 2009 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. If recognized, the less than $1 million of unrecognized tax benefits would reduce the effective income tax rate.

The amount KU recognized as interest expense and interest accrued related to unrecognized tax benefits was less than $1 million as of June 30, 2010 and December 31, 2009. The interest expense and interest accrued is based on IRS and Kentucky Department of Revenue large corporate interest rates for underpayment of taxes. At the date of adoption, the Company accrued less than $1 million in interest expense on uncertain tax positions. KU records the interest as interest expense and penalties as operating expenses in the income statement and accrued expenses in the balance sheet, on a pre-tax basis. No penalties were accrued by the Company through June 30, 2010.

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 was selected to receive $101 million in tax credits. 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 credits, which includes a full depreciation basis adjustment for the amount of the credits. Based on eligible construction expenditures incurred, KU recorded investment tax credits of $5 and $11 million during the three and six months ended June 30, 2009, decreasing current federal income taxes. As of December 31, 2009 KU had recorded its maximum credit of $101 million. The income tax expense impact from amortizing these credits over the life of the related property will begin when the facility is placed in service. As of June 30, 2010, TC2 has not been 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. During 2008 and 2009, the plaintiffs submitted amended complaints alleging additional claims for relief and seeking a preliminary injunction to implement certain elements of the requested relief. In July 2010, the court denied the plaintiffs' motion for preliminary injunction. A motion by the Federal government to dismiss the amended complaint is currently pending. The Company is not a party to this proceeding and is not able to predict the ultimate outcome of this matter.

A reconciliation of differences between KU's income tax expense at the statutory U.S. federal income tax rate and KU's actual income tax expense for the three and six month periods ended June 30 follows:

	Three Months Ended June 30,		Six Months Ended June 30,	
(in millions)	2010	2009	2010	2009
Statutory federal income tax expense	$ 17	$ 13	$ 41	$ 15
State income taxes, net of federal benefit	2	1	4	1
Qualified production activities deduction	(1)	-	(1)	(1)
Dividends received deduction related to EEI investment	-	(1)	-	(3)
Excess deferred tax on depreciation	-	(1)	(1)	(1)
Other differences	-	(1)	1	(1)
Income tax expense	$ 18	$ 11	$ 44	$ 10
Effective income tax rate	36.7%	29.7%	37.0%	23.3%

The amounts shown in the table above are rounded to the nearest $1 million; however, the effective income tax rate is based on actual underlying amounts.

State income taxes, net of federal benefit, were lower in the three and six months ended June 30, 2009, due to a coal credit recorded in 2009. The dividends received deduction is lower in the three and six months ended June 30, 2010, primarily due to the lack of EEI dividends in 2010.

Note 6 - Short-Term and Long-Term Debt

KU's long-term debt includes $228 million of pollution control bonds that are classified as current portion of long-term bonds 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 2002 Series A and B, 2004 Series A, 2006 Series B and 2008 Series A; Muhlenberg County 2002 Series A; and Mercer County 2000 Series A and 2002 Series A. Maturity dates for these bonds range from 2023 to 2034. The average annualized interest rate for these bonds during the three and six months ended June 30, 2010, was 0.37% and 0.36%, respectively. The average annualized interest rate for these bonds during the three and six months ended June 30, 2009, was 0.62% and 0.72%, respectively.

Pollution control bonds are obligations of KU issued in connection with tax-exempt pollution control revenue bonds issued by counties in Kentucky. A loan agreement obligates the Company to make debt service payments to the counties that equate to the debt service due from the counties on the related pollution control revenue bonds. The loan agreement is an unsecured obligation of the Company. Debt issuance expense is capitalized in either regulatory assets or current or long-term other assets and amortized over the lives of the related bond issues, consistent with regulatory practices.

Several of the KU pollution control bonds are insured by monoline bond insurers whose ratings have been reduced due to exposures relating to insurance of sub-prime mortgages. At June 30, 2010, 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. During 2008, the Company experienced "failed auctions" when there were insufficient bids for the bonds. When a failed auction occurs, the interest rate is set pursuant to a formula stipulated in the indenture. During the three months ended June 30, 2010 and 2009, the average rate on the auction rate bonds was 0.61% and 0.54%, respectively. During the six months ended June 30, 2010 and 2009, the average rate on the auction rate bonds was 0.44% and 0.59%, 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 June 2009, S&P downgraded the credit rating of Ambac, an insurer of the Company's bonds, from "A" to "BBB". As a result, S&P downgraded the rating on the Carroll County 2002 Series C bond from "A" to "BBB+" in June 2009. The S&P rating of this bond is now based on the rating of the Company rather than the rating of Ambac since the Company's rating is higher.

The Company 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
June 30, 2010	$ 400	$ 84	$ 316	0.34%
December 31, 2009	$ 400	$ 45	$ 355	0.20%

E.ON U.S. maintains revolving credit facilities totaling $313 million at June 30, 2010 and December 31, 2009, to ensure funding availability for the money pool. At June 30, 2010, 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 balances are as follows:

($ in millions)	Total Available	Amount Outstanding	Balance Available	Average Interest Rate
June 30, 2010	$ 313	$ 244	$ 69	1.51%
December 31, 2009	$ 313	$ 276	$ 37	1.25%

As of June 30, 2010, the Company maintained a bilateral line of credit with an unaffiliated financial institution totaling $35 million which matures in June 2012. At June 30, 2010, there was no balance outstanding under this facility. The Company also maintains letter of credit facilities that support $195 million of the $228 million of bonds that can be put back to the Company. Should the holders elect to put the bonds back and they cannot be remarketed, the letter of credit would fund the investor's payment.

There were no redemptions or issuances of long-term debt year-to-date through June 30, 2010. KU was in compliance with all debt covenants at June 30, 2010 and December 31, 2009.

See Note 2, Rates and Regulatory Matters, for certain debt refinancing and associated transactions which are anticipated by KU in connection with the PPL acquisition.

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 the Company's Annual Report for the year ended December 31, 2009 (including, but not limited to Notes 2, 9 and 12 to the financial statements of KU contained therein). See the Company's Annual Report regarding such commitments or contingencies.

Letters of Credit. KU has provided letters of credit as of June 30, 2010 and December 31, 2009, for on-balance sheet obligations totaling $198 million to support bonds of $195 million and a letter of credit for off-balance sheet obligations totaling less than $1 million to support certain obligations related to workers' compensation.

Owensboro Contract Litigation and Contract Termination. In May 2004, the City of Owensboro, Kentucky and OMU commenced a suit against KU concerning a long-term power supply contract (the "OMU Agreement") with KU. In May 2009, KU and OMU executed a settlement agreement resolving the matter on a basis consistent with prior court rulings and the Company has received the agreed settlement amounts. Pursuant to the settlement's operation, the OMU agreement terminated in May 2010. In connection with such termination, during the second quarter of 2010, KU has recorded relevant reserve amounts reflecting its estimates of remaining adjustments concerning prior accruals.

Construction Program. KU had approximately $55 million of commitments in connection with its construction program at June 30, 2010.

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. During 2009 and 2010, KU and LG&E have received several contractual notices from the TC2 construction contractor asserting historical force majeure and excusable event claims for a number of adjustments to the contract price, construction schedule, commercial operation date, liquidated damages or other relevant provisions. Further, during commissioning and testing activity conducted in the second quarter of 2010, the TC2 unit experienced burner malfunctions which have delayed the completion of commissioning and consequently the commercial operations date beyond the previously anticipated date of mid-June 2010. The Companies and the contractor are actively investigating the potential causes of and solutions to this development and currently estimate that commercial operation may be delayed until October 2010. The parties are continuing to discuss the existing force majeure, excusable delay and the recent burner malfunction issues and are attempting to resolve certain of them via settlement negotiations. The Company cannot currently estimate the ultimate outcome of these matters, including the extent, if any, that such outcome may result in materially increased costs for the construction of TC2, further changes in the TC2 construction completion or commercial operation dates or potential effects on levels of power purchases or wholesale sales due to such changed dates.

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. In September 2007, the Secretary of the Kentucky Environmental and Public Protection Cabinet issued a final Order upholding the permit. The environmental groups petitioned the EPA to object to the state permit and subsequent permit revisions. In determinations made in September 2008 and June 2009, the EPA rejected most of the environmental groups' claims but identified three permit deficiencies which the KDAQ addressed by revising the permit. In August 2009, the EPA issued an Order denying the remaining claims with the exception of two additional deficiencies which the KDAQ was directed to address. The EPA determined that the proposed permit subsequently issued by the KDAQ satisfied the conditions of the EPA Order although the agency recommended certain enhancements to the administrative record. In January 2010, the KDAQ issued a final permit revision incorporating the proposed changes to address the EPA objections. In March 2010, the environmental groups submitted a petition to the EPA to object to the permit revision, which is now pending before the EPA. The Company believes that the final permit as revised should not have a material adverse effect on its financial condition or results of operations. However, until the EPA issues a final ruling on the pending petition and all applicable appeals have been exhausted, the Company cannot predict the final outcome of this matter.

Thermostat Replacement. During January 2010, KU and LG&E announced a voluntary plan to replace certain thermostats, which had been provided to customers as part of the Companies' demand reduction programs, due to concerns that the thermostats may present a safety hazard. Under the plan, the Companies have replaced approximately 85% of the estimated 14,000 thermostats that need to be replaced. Total estimated costs associated with the replacement program are $2 million. However, the Companies cannot fully predict the ultimate outcome of the replacement program or other effects or developments which may be associated with the thermostat replacement matter at this time.

Environmental Matters. The Company'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.

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 place in the interim. The remand of the CAIR results in some uncertainty with respect to certain other EPA or state programs and proceedings and the Companies' compliance plans relating thereto due to the interconnection of the CAIR with such associated programs.

In July 2010, the EPA issued the proposed CATR, which serves to replace the CAIR. The CATR provides for a two-phase SO_2 reduction program with Phase I reductions due by 2012, and Phase II reductions due by 2014. The CATR provides for NOx reductions in 2012, but the EPA advised that it is studying whether additional NOx reductions should be required for 2014. The CATR is more stringent than the CAIR as it accelerates certain compliance dates and provides for only intrastate and limited interstate trading of emission allowances. In addition to its preferred approach, the EPA is seeking comment on an alternative approach which would provide for individual emission limits at each power plant. The EPA has announced that it will propose additional "transport" rules to address compliance with revised NAAQS standards for ozone and particulate matter which will be issued by the EPA in the future, as discussed below. At present, KU is not able to predict the outcomes of the legal and regulatory proceedings related to the CATR; however, such outcomes, while not yet determinable, could result in significant costs to the Company.

In January 2010, the EPA proposed a revised NAAQS for ozone which would increase the stringency of the standard. In addition, the EPA published final revised NAAQS standards for nitrogen dioxide ("NO_2") and SO_2 in February 2010 and June 2010, respectively, which are more stringent than previous standards. Depending on the level of action determined necessary to bring local nonattainment areas into compliance with the revised NAAQS standards, KU's power plants are potentially subject to requirements for additional reductions in SO_2 and NOx emissions. Until such time as the relevant regulatory agencies make nonattainment designations and determine reductions required from local emissions sources, the Company is unable to determine what, if any, additional requirements may be imposed to achieve compliance with the revised NAAQS standards.

The costs to implement the respective proposed or final more stringent ozone, NO_2, SO_2, particulate matter or other standards under the NAAQS or CATR are not currently determinable. Depending upon whether the final rules or implementation methods incorporate additional emissions reduction requirements and the amounts of such reductions, such costs could be significant.

Hazardous Air Pollutants. As provided in 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 rules with different or more stringent requirements for reduction of mercury and other hazardous air pollutants. 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. If the new rules are more stringent and require additional reductions in emissions, the costs to achieve such reductions, while not yet determinable, could be significant.

Acid Rain Program. 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 Clean Air Act also contains 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 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 the 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 mandated by the NOx SIP Call, KU installed additional NOx controls, including SCR technology, during the 2000 through 2009 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 ECR 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 $235 million during the 2010 through 2012 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.

GHG Developments. 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. As discussed below, 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, 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. The current administration has announced its support for the adoption of mandatory GHG reduction requirements at the federal level. The United States and other countries met in Copenhagen, Denmark in December 2009, in an effort to negotiate a GHG reduction treaty to succeed the Kyoto Protocol, which is set to expire in 2013. In Copenhagen, the U.S. made a nonbinding commitment to, among other things, seek to reduce GHG emissions to 17% below 2005 levels by 2020 and provide financial support to developing countries. The United States and other nations are scheduled to meet in Cancun, Mexico in late 2010 to continue negotiations toward a binding agreement.

GHG Legislation KU is monitoring on-going efforts to enact GHG reduction requirements and requirements governing carbon sequestration at the state and federal level and is assessing potential impacts of such programs and strategies to mitigate those impacts. In June 2009, the U.S. House of Representatives passed the American Clean Energy and Security Act of 2009, which is a comprehensive energy bill containing the first-ever nation-wide GHG cap and trade program. The bill would provide for reductions in GHG emissions of 3% below 2005 levels by 2012, 17% by 2020 and 83% by 2050. In order to cushion potential rate impacts for utility customers, approximately 43% of emissions allowances would initially be allocated at no cost to the electric utility sector, with this allocation gradually declining to 7% in 2029 and zero thereafter. The bill would also establish a renewable electricity standard requiring utilities to meet 20% of their electricity demand through renewable energy and energy efficiency by 2020. The bill contains additional provisions regarding carbon capture and sequestration, clean transportation, smart grid advancement, nuclear and advanced technologies and energy efficiency.

In September 2009, the Clean Energy Jobs and American Power Act, which is largely patterned on the House legislation, was introduced in the U.S. Senate. The Senate bill raises the emissions reduction target for 2020 to 20% below 2005 levels and does not include a renewable electricity standard. While the initial bill lacked detailed provisions for the allocation of emissions allowances, a subsequent revision incorporated allowance allocation provisions similar to the House bill. In 2010, Senators Kerry and Lieberman and others have undertaken additional work to draft GHG legislation but have introduced no bill in the Senate to date. In July 2010, Senate Majority Leader Reid announced that he did not anticipate that GHG legislation would be brought to the Senate floor in the current session. The Company is closely monitoring the progress of pending energy legislation, but the prospect for passage of comprehensive GHG legislation in 2010 is uncertain.

GHG Regulations. In April 2007, the U.S. Supreme Court ruled that the EPA has the authority to regulate GHG under the Clean Air Act. In April 2009, the EPA issued a proposed endangerment finding concluding that GHGs endanger public health and welfare, which is an initial rulemaking step under the Clean Air Act. A final endangerment finding was issued in December 2009. In September 2009, the EPA issued a final GHG reporting rule requiring reporting by facilities with annual GHG emissions equivalent to at least 25,000 tons of carbon dioxide. A number of the Company's facilities will be required to submit annual reports commencing with calendar year 2010. In May 2010, the EPA issued a final GHG "tailoring" rule requiring new or modified sources with GHG emissions equivalent to at least 75,000 tons of carbon dioxide to obtain permits under the Prevention of Significant Deterioration Program. Such new or modified facilities would be required to install Best Available Control Technology. While the Company is unaware of any currently available GHG control technology that might be required for installation on new or modified power plants, it is currently assessing the potential impact of the rule. The final rule will apply to new and modified power plants beginning in January 2011.

The Company is unable to predict whether mandatory GHG reduction requirements will ultimately be enacted through legislation or regulations.

GHG Litigation. A number of lawsuits have been filed asserting common law claims including nuisance, trespass and negligence against various companies with GHG emitting facilities. In October 2009, a three judge panel of the United States Court of Appeals for the 5th Circuit in the case of Comer v. Murphy Oil reversed a lower court, holding that private plaintiffs have standing to assert certain common law claims against more than 30 utility, oil, coal and chemical companies. In March 2010, the court vacated the opinion of the three-judge panel and granted a motion for rehearing but subsequently denied the appeal due to the lack of a quorum. The appellate ruling leaves in effect the lower court ruling dismissing the plaintiffs' claims. The Comer complaint alleges that GHG emissions from the defendants' facilities contributed to global warming which increased the intensity of Hurricane Katrina. E.ON, the indirect parent of KU and LG&E, was included as a defendant in the complaint but has not been subject to the proceedings due to the failure of the plaintiffs to pursue service under the applicable international procedures. KU and LG&E are currently unable to predict further developments in the Comer case. KU and LG&E continue to monitor relevant GHG litigation to identify judicial developments that may be potentially relevant to their operations.

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. The Company is not able to estimate the outcome or potential effects of these matters, including whether substantial fines, penalties or remedial measures may result.

Ghent New Source Review NOV. In March 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 contends that the work in question, as pollution control projects, was exempt from the requirements cited by the EPA. In December 2009, the EPA issued a Section 114 information request seeking additional information on this matter. In March 2010, the Company received an EPA settlement proposal providing for imposition of additional permit limits and emission controls and anticipates continued settlement negotiations with the EPA. Depending on the provisions of a final settlement or the results of litigation, if any, resolution of this matter could involve significant increased operating and capital expenditures. 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.

Ash Ponds, Coal-Combustion Byproducts and Water Discharges. The EPA has undertaken various initiatives in response to the December 2008 impoundment failure at the Tennessee Valley Authority's Kingston power plant, which resulted in a major release of coal combustion byproducts into the environment. The EPA issued information requests to utilities throughout the country, including KU, to obtain information on their ash ponds and other impoundments. In addition, the EPA inspected a large number of impoundments located at power plants to determine their structural integrity. The inspections included several of KU's impoundments, which the EPA found to be in satisfactory condition. In June 2010, the EPA published proposed regulations for coal combustion byproducts handled in landfills and ash ponds. The EPA has proposed two alternatives: (1) regulation of coal combustion byproducts in landfills and ash ponds as a hazardous waste or (2) regulation of coal combustion byproducts as a solid waste with minimum national standards. Under both alternatives, the EPA has proposed safety requirements to address the structural integrity of ash ponds. In addition, the EPA will consider potential refinements of the provisions for beneficial reuse of coal combustion byproducts. The EPA has also announced plans to develop revised effluent limitations guidelines and standards governing discharges from power plants. The Company is monitoring these ongoing regulatory developments but will be unable to determine the impact until such time as new rules are finalized. Should the final rules require more stringent storage or disposal practices for these byproducts than currently in place or indirectly cause changes in other operational or generation practices, the costs of such revised practices, while not yet determinable, could be significant.

In May 2010, the Kentucky Waterways Alliance and other environmental groups filed a petition with the Kentucky Energy and Environment Cabinet challenging the Kentucky Pollutant Discharge Elimination System permit issued in April 2010, which covers water discharges from the Trimble County Station. Due to the preliminary stage of the proceedings, the Company is currently unable to predict the outcome or precise impact of this matter.

As a company with significant coal-fired generating assets, KU could be substantially impacted by pending or future environmental rules or legislation requiring mandatory reductions in GHG emissions or other air emissions, imposing more stringent standards on discharges to waterways, or establishing additional requirements for handling or disposal of coal combustion byproducts. However, the precise impact on its operations, including the reduction targets and deadlines that would be applicable, cannot be determined prior to the finalization of such requirements. While the Company believes that many costs of complying with such pending or future requirements would likely be recoverable under the ECR or other potential cost-recovery mechanisms, this cannot be assured.

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 a prior Section 114 information request from the EPA relating to new-source issues at KU's Ghent 2 generation unit; completed settlement with state regulators regarding particulate limits in the air permit for KU's Tyrone generating station; remediation activities for or other risks relating to elevated Polychlorinated Biphenyl 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 the GHG emissions from the Company's generating stations. Based on analysis to date, the resolution of these matters is not expected to have a material impact on the Company's operations.

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 FERC regulations under the Public Utility Holding Company Act of 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, power purchased expense and other operations and maintenance expenses. KU's intercompany electric revenues and power purchased expense for the three and six months ended June 30, were as follows:

	Three Months Ended June 30,		Six Months Ended June 30,	
(in millions)	2010	2009	2010	2009
Electric operating revenues from LG&E	$ 4	$ 6	$ 11	$ 16
Power purchased from LG&E	24	28	49	60

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 interest expense to affiliated companies for the three and six months ended June 30 was as follows:

	Three Months Ended June 30,		Six Months Ended June 30,	
(in millions)	2010	2009	2010	2009
Interest on Fidelia loans	$ 19	$ 17	$ 37	$ 33

Interest expense paid to E.ON U.S. on the money pool arrangement was less than $1 million for the three and six months ended June 30, 2010 and 2009.

Other Intercompany Billings

E.ON U.S. Services provides the Company 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 the Company, 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 and hourly 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 the Company on behalf of other non-regulated businesses which are reimbursed through E.ON U.S. Services.

Intercompany billings to and from KU for the three and six months ended June 30, were as follows:

	Three Months Ended June 30,		Six Months Ended June 30,	
(in millions)	2010	2009	2010	2009
E.ON U.S. Services billings to KU	$ 67	$ 38	$ 117	$ 78
KU billings to LG&E	1	36	1	47
LG&E billings to KU	12	-	19	-
KU billings to E.ON U.S. Services	-	1	-	2

In March 2009, the Company received capital contributions of $50 million from its common shareholder, E.ON U.S.

Intercompany Balances

The Company had the following balances with its affiliates as of June 30, 2010 and December 31, 2009:

(in millions)	June 30, 2010	December 31, 2009
Accounts receivable from E.ON U.S.	$ -	$ 9
Accounts payable to LG&E	18	53
Accounts payable to E.ON U.S. Services	15	20
Accounts payable to E.ON U.S.	18	-
Accounts payable to Fidelia	15	15
Notes payable to E.ON U.S.	84	45
Long-term debt to Fidelia (including current portion of $33 million)	1,331	1,331

Note 9 – Subsequent Events

Subsequent events have been evaluated through August 11, 2010, the date of issuance of these statements, and these statements contain all necessary adjustments and disclosures resulting from that evaluation.

On July 30, 2010, the Kentucky Commission issued an Order in the current base rate case approving all the provisions in the stipulation, with rates effective for service rendered on and after August 1, 2010.

On July 16, 2010, the FERC issued an Order on the one remaining renewable resource issue from the FERC rate case. The Order indicated that KU is not required to allocate a portion of any required renewable resources to the twelve municipalities, thus substantially resolving this issue.

Management's Discussion and Analysis

Overview

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 516,000 customers in 77 counties in central, southeastern and western Kentucky, to approximately 29,000 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 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. KU's affiliate, LG&E, is a regulated public utility engaged in the generation, transmission, distribution and sale of electric energy and the storage, distribution and sale of natural gas in Kentucky.

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 six-month periods ended June 30, 2010, and should be read in connection with the condensed financial statements and notes thereto and the Annual Report for the year ending December 31, 2009. Dollars are in millions, unless otherwise noted.

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, 2009.

PPL Acquisition

On April 28, 2010, E.ON U.S. announced that a Purchase and Sale Agreement (the "Agreement") had been entered into among E.ON US Investments, PPL and E.ON.

The Agreement provides for the sale of E.ON U.S. to PPL. Pursuant to the Agreement, at closing, PPL will acquire all of the outstanding limited liability company interests of E.ON U.S. for cash consideration of $2.1 billion. In addition, pursuant to the Agreement, PPL agreed to assume $925 million of pollution control bonds and to repay indebtedness owed by E.ON U.S. and its subsidiaries to E.ON US Investments and its affiliates. Such affiliate indebtedness is currently estimated to be $4.6 billion. The aggregate consideration payable by PPL on closing, $7.6 billion (including the assumed indebtedness), is subject to adjustment for specified incremental investment in E.ON U.S. that will potentially be made by E.ON US Investments and its affiliates prior to closing.

The transaction is subject to customary closing conditions, including the expiration or termination of the applicable waiting period under the Hart-Scott-Rodino Act, receipt of required regulatory approvals (including state regulators in Kentucky, Virginia and Tennessee, and the FERC) and the absence of injunctions or restraints imposed by governmental entities. Subject to receipt of required approvals, the transaction is expected to close by the end of 2010. Change of control and financing-related applications were filed on May 28, 2010, with the Kentucky Commission and on June 15, 2010, with the Virginia Commission and the Tennessee Regulatory Authority. An application with the FERC was filed on June 28, 2010. During the second quarter of 2010, a number of intervenors made entries into the Kentucky Commission proceedings and data request filings and responses occurred. Hearings in the Kentucky Commission proceedings are scheduled for September 8, 2010. Early termination of the final Hart-Scott-Rodino waiting period was received on August 2, 2010.

Based upon credit and financial market conditions, the anticipated PPL acquisition and other factors, the Company anticipates completing certain re-financing transactions and, where applicable, has applied for regulatory approvals for such transactions. KU anticipates issuing up to $1.6 billion in public first mortgage bonds, the proceeds of which will substantially be used to refund existing long-term intercompany debt. As required by existing covenants, in connection with the issuance of any such secured debt, KU would also collateralize certain outstanding pollution control bond debt series which are presently unsecured. Upon such collateralization, approximately $351 million in existing pollution control debt would become secured debt, supported by a first mortgage lien. Subject to regulatory approvals and other conditions, KU may complete these transactions, in whole or in part, during late 2010 and early 2011.

Regulatory Matters

In January 2010, KU filed an application with the Kentucky Commission requesting an increase in electric base rates of approximately 12%, or $135 million annually, including an 11.5% return on equity. KU requested the increase, based on the twelve month test year ended October 31, 2009, to become effective on and after March 1, 2010. The requested rates were suspended until August 1, 2010. A number of intervenors entered the rate case, including the Kentucky Attorney General's office, certain representatives of industrial and low-income groups and other third parties, and submitted filings challenging the Company's requested rate increases, in whole or in part. A hearing was held on June 8, 2010. KU and all of the intervenors except the AG agreed to a stipulation providing for an increase in electric base rates of $98 million annually and filed a request with the Kentucky Commission to approve such settlement. An Order in the proceeding was issued in July 2010, approving all the provisions in the stipulation, with rates effective on and after August 1, 2010.

In January 2009, a significant ice storm passed through KU's service territory causing approximately 199,000 customer outages and was followed closely by a severe wind storm in February 2009 that caused approximately 44,000 customer outages. KU incurred $57 million in incremental operation and maintenance expenses and $33 million in capital expenditures related to the restoration following the two storms. The Company filed an application with the Kentucky Commission in April 2009, requesting approval to establish a regulatory asset and defer for future recovery approximately $62 million in incremental operation and maintenance expenses related to the storm restoration. In September 2009, the Kentucky Commission issued an Order allowing the Company to establish a regulatory asset of up to $62 million based on its actual costs for storm damages and service restoration due to the January and February 2009, storms. In

September 2009, the Company established a regulatory asset of $57 million for actual costs incurred. The Company received approval in its current base rate case to recover this asset over a ten year period beginning August 1, 2010.

Virginia Rate Case

In June 2009, KU filed an application with the Virginia Commission requesting an increase in electric base rates for its Virginia jurisdictional customers in an amount of $12 million annually or approximately 21%. The proposed increase reflected a proposed rate of return on rate base of 8.586% based upon a return on equity of 12%. During December 2009, KU and the Virginia Commission Staff agreed to a Stipulation and Recommendation authorizing base rate revenue increases of $11 million annually and a return on rate base of 7.846% based on a 10.5% return on common equity. A public hearing was held during January 2010. As permitted, pursuant to a Virginia Commission Order, KU elected to implement the proposed rates effective November 1, 2009, on an interim basis. In March 2010, the Virginia Commission issued an Order approving the stipulation, with the increased rates to be put into effect as of April 1, 2010. As part of the stipulation, KU refunded certain amounts collected since November 2009, consisting of interim rates in excess of the ultimate approved rates. These refunds, including interest, aggregated approximately $1 million and were made during May and June 2010. During the third quarter of 2010, a report is expected to be filed detailing the costs of the refunds, the accounts charged and details validating that all refunds have been made.

FERC Wholesale Rate Case

In September 2008, KU filed an application with the FERC for increases in electric base rates applicable to wholesale power sales contracts or interchange agreements involving, collectively, twelve Kentucky municipalities. The application requested a shift from current, all-in stated unit charge rates to an unbundled formula rate, including an annual adjustment mechanism. In May 2009, the FERC issued an Order approving a settlement among the parties in the case, incorporating increases of approximately 3% from prior rates and a return on equity of 11%. In May 2010, KU submitted to the FERC the proposed current annual adjustment to the formula rate. This updated rate became effective on July 1, 2010, subject to certain review procedures by the wholesale requirements customers and the FERC, including potential refunds in the case of disallowed costs or charges.

By mutual agreement, the parties' settlement of the 2008 application left outstanding the issue of whether KU must allocate to the municipal customers a portion of renewable resources it may be required to procure on behalf of its retail ratepayers. In August 2009, the FERC accepted the issue for briefing and the parties completed briefing submissions during 2009. An Order was issued by the FERC in July 2010, indicating that KU is not required to allocate a portion of any renewable resources to the twelve municipalities, thus resolving the remaining issue.

Environmental Matters

General. Protection of the environment is a major priority for KU and a significant element of its business activities. KU's properties and operations are subject to extensive environmental-related oversight by federal, state and local regulatory agencies, including via air quality, water quality, waste management and similar laws and regulations. Therefore, KU must conduct its operations in accordance with numerous permit and other requirements issued under or contained in such laws or regulations.

Climate Change. Recent developments continue to indicate an increased possibility of significant climate change or GHG legislation or regulation, at the international, federal, regional and state levels. During December 2009, as part of the United Nation's Copenhagen Accord, the United States agreed to a non-binding goal to reduce GHG emissions to 17% below 2005 levels by 2020. Additionally, during 2009, the U.S. House of Representatives passed comprehensive GHG legislation, which included a number of measures to limit GHG emissions and achieve GHG emission reduction targets below 2005 levels of 3%, 17% and 83% by 2012, 2020 and 2050, respectively, and the U.S. Senate is considering companion legislation. In late 2009, the EPA issued or proposed various regulatory initiatives relating to GHG matters, including an endangerment finding relating to mobile sources of GHGs, a GHG reporting requirement and a rule relating to permitting requirements for new or modified GHG emission sources. Finally, a number of U.S. states, although not currently including Kentucky, have adopted GHG-reduction legislation or regulation of various sorts. The developing GHG initiatives include a number of differing structures and formats, including direct limitations on GHG sources, issuance of allowances for GHG emissions, cap-and-trade programs for such allowances, renewable or alternative generation portfolio standards and mechanisms relating to demand reduction, energy efficiency, smart-grid, transmission expansion, carbon-sequestration or other GHG-reducing efforts. While the final terms and impacts of such initiatives cannot be estimated, KU, as a primarily coal-fired utility, could be highly affected by such proceedings.

The cost to KU and the effect on KU's business of complying with potential GHG restrictions will depend upon the details of the programs ultimately enacted. Some of the design elements which may have the greatest effect on KU include (a) the required levels and timing of any carbon caps or limits, (b) the emission sources covered by such caps or limits, (c) transition and mitigation provisions, such as phase-in periods, free allowances or price caps, (d) the availability and pricing of relevant GHG-reduction technologies, goods or services and (e) economic, market and customer reaction to electricity price and demand changes due to GHG limits. While the costs to comply with future GHG developments are not currently determinable, such costs could be significant.

Ultimately, environmental matters or potential environmental matters can represent an important element of current or future potential capital requirements, future unit retirement or replacement decisions, supply and demand for electricity, operating and maintenance expenses or compliance risks for the Company. While KU currently anticipates that many of such direct costs or effects may be recoverable through rates or other regulatory mechanisms, particularly with respect to coal-related generation, the availability, timing or completeness of such rate recovery cannot be assured. Ultimately, climate change matters could result in material effects on KU's results of operations, liquidity and financial position. See Management's Discussion and Analysis and Note 7 of Notes to Condensed Financial Statements for additional 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 June 30, 2010, Compared to
Three Months Ended June 30, 2009

Net Income

Net income was $31 million for the three months ended June 30, 2010, compared to $26 million for the same period in 2009. The increase was primarily the result of the following:

	Three Months Ended June 30, 2010	2009	Increase (Decrease)
Total operating revenues	$ 350	$ 305	$ 45
Total operating expenses	279	252	27
Operating income	71	53	18
Equity in loss of unconsolidated venture	1	1	-
Other expense (income) - net	1	(3)	4
Interest expense	1	1	-
Interest expense to affiliated companies	19	17	2
Income before income taxes	49	37	12
Income tax expense	18	11	7
Net income	$ 31	$ 26	$ 5

Operating Revenues

The $45 million increase in operating revenues in the three months ended June 30, 2010, was primarily due to:

	Increase (Decrease)
Retail sales volumes (a)	$ 29
Retail FAC costs billed to customers due to higher fuel prices	11
ECR surcharge due to increased recoverable capital spending	3
DSM revenue due to increased recoverable program spending	2
Retail base rates	2
Miscellaneous operating revenues	1
Wholesale sales to LG&E due to volume (b)	(3)
	$ 45

(a) Primarily due to increased consumption by residential customers as a result of increased cooling degree days and higher energy usage by industrial customers as a result of improved economic conditions
(b) Primarily due to increased energy demand from industrial and residential customers at LG&E and increased coal-fired generation unit outages at LG&E in the second quarter of 2010. Via a mutual agreement, KU purchases LG&E's lower cost electricity to serve KU's native load, and KU sells its higher cost electricity to LG&E for LG&E to make wholesale sales.

Operating 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. Operating expenses for the three months ended June 30, follow:

	Three Months Ended June 30, 2010	Three Months Ended June 30, 2009	Increase (Decrease)
Fuel for electric generation	$ 119	$ 100	$ 19
Power purchased	40	43	(3)
Other operation and maintenance expenses	86	76	10
Depreciation and amortization	34	33	1
Total operating expenses	$ 279	$ 252	$ 27

Fuel for Electric Generation

The $19 million increase in fuel for electric generation in the three months ended June 30, 2010, was primarily due to increased volumes of fuel usage due to increased native load sales.

Power Purchased

The $3 million decrease in power purchased expense in the three months ended June 30, 2010, was primarily due to:

	Increase (Decrease)
Third-party purchased volumes for native load	$ (6)
Purchases from LG&E due to volume (a)	(4)
Demand payments for third-party purchases	(2)
OMU settlement received in 2009 (b)	6
Prices for purchases used to serve retail customers	3
	$ (3)

(a) Via a mutual agreement, KU purchases LG&E's lower cost electricity to serve KU's native load. LG&E provided lower volumes due to its increased energy demand from residential and industrial customers from warmer temperatures and due to increased coal-fired generation unit outages during the second quarter of 2010.

(b) See Note 7 of Notes to Condensed Financial Statements for further discussion of the OMU settlement.

Other Operation and Maintenance Expenses

Other operation and maintenance expenses increased $10 million in the three months ended June 30, 2010, due to $7 million of increased other operation expenses and $3 million of increased maintenance expenses.

Other Operation Expenses

The $7 million increase in other operation expenses in the three months ended June 30, 2010, was primarily due to:

	Increase (Decrease)
Steam expense due to increased generation in 2010	$ 2
Transmission expense	2
OMU settlement received in 2009	2
DSM expense due to expanded programs and new projects	2
Bad debt expense	1
MISO RSG resettlements incurred in 2009	(1)
Property and other taxes reduction resulting from an increased coal tax credit	(1)
	$ 7

Maintenance Expenses

The $3 million increase in maintenance expenses in the three months ended June 30, 2010, was primarily due to:

	Increase (Decrease)
Combustion turbine maintenance	$ 1
Administrative and general	1
Distribution expense	1
	$ 3

Other Expense (Income) – net

The $4 million increase in other expense (income) – net in the three months ended June 30, 2010, was primarily due to:

	Increase (Decrease)
Discontinuance of allowance for funds used during construction on ECR projects resulting from FERC rate case	$ 1
Depreciation expense on TC2 joint-use assets held for future use	1
Gain on key man life insurance payout in 2009	1
Decreased interest income from other loans and receivables	1
	$ 4

Interest Expense

The $2 million increase in interest expense, including interest expense to affiliated companies, in the three months ended June 30, 2010, was primarily due to increased intercompany notes outstanding.

Income Tax Expense

See Note 5 of Notes to Condensed Financial Statements for a reconciliation of differences between the statutory U.S. federal income tax expense and KU's income tax expense.

Six Months Ended June 30, 2010, Compared to
Six Months Ended June 30, 2009

Net Income

Net income was $75 million for the six months ended June 30, 2010, compared to $33 million for the same period in 2009. The increase was primarily the result of the following:

	Six Months Ended June 30, 2010	2009	Increase (Decrease)
Total operating revenues	$ 730	$ 668	$ 62
Total operating expenses	572	596	(24)
Operating income	158	72	86
Equity in earnings of unconsolidated venture	(2)	(1)	(1)
Other expense - net	1	(6)	7
Interest expense	3	3	-
Interest expense to affiliated companies	37	33	4
Income before income taxes	119	43	76
Income tax expense	44	10	34
Net income	$ 75	$ 33	$ 42

Operating Revenues

The $62 million increase in operating revenues in the six months ended June 30, 2010, was primarily due to:

	Increase (Decrease)
Retail sales volumes (a)	$ 59
DSM revenue due to increased recoverable program spending	7
Miscellaneous operating revenue (b)	6
Merger surcredit	1
Wholesale sales to LG&E due to volume (c)	(5)
Retail FAC	(3)
Gains in energy marketing financial swaps	(2)
Wholesale sales to LG&E due to fuel price	(1)
	$ 62

(a) Primarily due to increased consumption by residential customers as a result of increased cooling degree days and higher energy usage by industrial customers as a result of improved economic conditions

(b) Primarily related to increased late payment charges ($4 million) and transmission service revenues ($1 million)
(c) Primarily due to increased energy demand from industrial and residential customers at LG&E and increased coal-fired generation unit outages at LG&E in the first six months of 2010. Via a mutual agreement, KU purchases LG&E's lower cost electricity to serve KU's native load and KU sells its higher cost electricity to LG&E for LG&E to make wholesale sales.

Operating 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. Operating expenses for the six months ended June 30 follow:

	Six Months Ended June 30, 2010	Six Months Ended June 30, 2009	Increase (Decrease)
Fuel for electric generation	$ 245	$ 215	$ 30
Power purchased	94	107	(13)
Other operation and maintenance expenses	165	208	(43)
Depreciation and amortization	68	66	2
Total operating expenses	$ 572	$ 596	$ (24)

Fuel for Electric Generation

The $30 million increase in fuel for electric generation in the six months ended June 30, 2010, was primarily due to:

	Increase (Decrease)
Fuel usage volumes due to increased native load sales	$ 41
Commodity and transportation costs for coal	(11)
	$ 30

Power Purchased

The $13 million decrease in power purchased expense in the six months ended June 30, 2010, was primarily due to:

	Increase (Decrease)
Purchases from LG&E due to volume (a)	$ (10)
Third-party purchased volumes for native load	(6)
Demand payments for third-party purchases	(2)
Purchases from LG&E due to fuel costs	(1)
OMU settlement received in 2009 (b)	6
	$ (13)

(a) Via a mutual agreement, KU purchases LG&E's lower cost electricity to serve KU's native load. LG&E provided lower volumes due to its increased energy demand from residential and industrial customers from colder weather in the first quarter and warmer temperatures in the second quarter of 2010, and due to increased coal-fired generation unit outages in the first six months of 2010.
(b) See Note 7 of Notes to Condensed Financial Statements for further discussion of the OMU settlement

Other Operation and Maintenance Expenses

Other operation and maintenance expenses decreased $43 million in the six months ended June 30, 2010, due to $53 million of decreased maintenance expenses and $10 million of increased other operation expenses.

Maintenance Expenses

The $53 million decrease in maintenance expenses in the six months ended June 30, 2010 was primarily due to:

	Increase (Decrease)
Distribution expense incurred in 2009 due to winter storm restoration	$ (51)
Turbine outages in 2009	(3)
Transmission expense	(1)
Administrative and general expense (a)	2
	$ (53)

(a) Labor and system maintenance contracts resulting from a significant in-house customer information system project completed during the second quarter of 2009

Other Operation Expenses

The $10 million increase in other operation expenses in the six months ended June 30, 2010, was primarily due to:

	Increase (Decrease)
Transmission expense (a)	$ 5
Administrative and general (b)	4
Steam expense due to increased generation in 2010	3
DSM expense due to expanded programs and new projects	3
OMU settlement received in 2009	2
Distribution expense resulting from 2009 winter storm restoration	(4)
Property and other tax reduction resulting from an increased coal tax credit	(2)
Other power expense due to MISO RSG resettlements in 2009	(1)
	$ 10

(a) Primarily due to the establishment of a regulatory asset approved by the Kentucky Commission for the EKPC settlement in 2009 and six months of amortization expense recorded in 2010, as well as increased transmission expense due to transmission charges for FERC jurisdictional municipal customers now unbundled from energy.
(b) Primarily due to bad debt expense increased due to higher billed revenues, implementation of a late payment charge and a higher net charge-off percentage

Equity in Earnings of Unconsolidated Venture

The $1 million increase in equity in earnings of unconsolidated venture in the six months ended June 30, 2010, was primarily due to higher EEI earnings resulting from increased market prices.

Other Expense – net

The $7 million increase in other expense – net in the six months ended June 30, 2010, was primarily due to:

	Increase (Decrease)
Discontinuance of allowance for funds used during construction on ECR projects resulting from FERC rate case	$ 3
Depreciation expense on TC2 joint-use assets held for future use	2
Gain on key man life insurance payout in 2009	1
Decreased interest income from other loans and receivables	1
	$ 7

Interest Expense

The $4 million increase in interest expense, including interest expense to affiliated companies, in the six months ended June 30, 2010, was primarily due to increased intercompany notes outstanding.

Income Tax Expense

See Note 5 of Notes to Condensed Financial Statements for a reconciliation of differences between the statutory U.S. federal income tax expense and KU's income tax expense.

Financial Condition

Liquidity and Capital Resources

(millions)	June 30, 2010	December 31, 2009
Cash and cash equivalents	$ 3	$ 2
Current portion of long-term bonds	228	228
Current portion of long-term debt to affiliated company	33	33
Notes payable to affiliated company	84	45

The $1 million increase in KU's cash and cash equivalents in the six months ended June 30, 2010, was primarily the net result of:

	Increase (Decrease)
Cash provided by operating activities	$ 155
A net increase in short-term borrowings from affiliated company	39
Construction expenditures	(145)
Expenditures to purchase assets from affiliate	(48)
	$ 1

Working Capital Deficiency

As of June 30, 2010, KU had a working capital deficiency of $189 million, primarily due to the terms of certain tax-exempt bonds totaling $228 million, which allow the investors to put the bonds back to the Company causing them to be classified as current portion of long-term bonds. The Company has adequate liquidity facilities to repurchase any bonds put back to the Company. Working capital deficiencies can be funded through an intercompany money pool agreement through bilateral lines of credit or drawings under letters of credit. See Note 6 of Notes to Condensed Financial Statements. KU believes that its sources of funds will be sufficient to meet the needs of its business in the foreseeable future.

Auction Rate Securities

Auctions for auction rate securities issued by KU continued to fail during the quarter. KU did not hold any of its own auction rate securities at June 30, 2010 and December 31, 2009. See Note 6 of Notes to Condensed Financial Statements for further discussion of auction rate securities.

Debt

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 2009, 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 2011, allowing short-term borrowing of up to $400 million. These short-term funds are made available via the Company's participation 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.

See Note 6 of Notes to Condensed Financial Statements for information on redemptions, maturities and issuances of long-term debt.

Common Stock Dividends

During 2010, the Company has not paid dividends to its common shareholder, E.ON U.S. KU uses net cash generated from its operations and external financing (including financing from affiliates) to fund the payment of dividends. Future dividends, declared at the discretion of the Board of Directors, will be dependent upon future earnings, financial requirements and other factors.

Credit Ratings

The Company's debt ratings as of June 30, 2010, were:

	Moody's	S&P
Unenhanced 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. In connection with E.ON U.S.'s announcement that E.ON and E.ON US Investments Corp. had entered into a definitive agreement with PPL to sell to PPL all the equity interests of E.ON U.S., Moody's placed the debt ratings of the Company under review for possible downgrade. S&P affirmed the existing ratings of the Company. See Note 6 of Notes to Condensed 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.

KU has various derivative and non-derivative contracts, including contracts for the sale and purchase of electricity and fuel and interest rate instruments, which contain provisions requiring KU to post additional collateral or permit the counterparty to terminate the contract if KU's credit rating were to fall below investment grade. At June 30, 2010, if KU's credit rating had been below investment grade, the Company would not have been required to post collateral to counterparties for both derivative and non-derivative commodity and commodity-related contracts used in its generation, marketing and trading operations and interest rate contracts.

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, 2012, to total approximately $1.1 billion, consisting primarily of the following:

($ in millions)	
Construction of generation assets	$ 290
Construction of distribution assets	250
Ash pond and landfill projects	235
Brown SCR	150
Installation of FGDs on Ghent and Brown units	130
Information technology projects	35
Other projects	25
Construction of TC2 (includes $5 million for environmental controls)	25
	$ 1,140

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. Credit market conditions can affect aspects of the availability, terms or methods in which the Company funds its capital requirements. KU anticipates funding future capital requirements through operating cash flow, debt and/or infusions of capital from its parent.

Controls and Procedures

Management 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 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 condensed 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.

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, management has assessed the effectiveness of the Company's internal control over financial reporting as of December 31, 2009, using the criteria set forth by the Committee of Sponsoring Organizations of the Treadway Commission in *Internal Control – Integrated Framework.* Management has concluded that, as of December 31, 2009, the Company's internal control over financial reporting was effective based on those criteria. There have been no changes in the Company's internal control over financial reporting that occurred during the six months ended June 30, 2010, that has materially affected or is reasonably likely to materially affect the Company's internal control over financial reporting.

The effectiveness of the Company's internal control over financial reporting as of December 31, 2009, was audited by PricewaterhouseCoopers LLP, an independent accounting firm, as stated in its report which is included in the 2009 KU Annual Report.

Legal Proceedings

For a description of the significant legal proceedings, including, but not limited to, certain rates and regulatory, environmental, climate change and litigation matters, involving KU, reference is made to the information under the following captions of the Company's Annual Report for the year ended December 31, 2009: 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, 7 and 9 of this quarterly report. Except as described in this quarterly report, to date, the proceedings reported in the Company's Annual Report for the year ended December 31, 2009 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, the Company 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 the Company's financial position or results of operations.

KENTUCKY UTILITIES COMPANY
FINANCIAL STATEMENTS

SEPTEMBER 30, 2010

Kentucky Utilities Company

Condensed Financial Statements and Additional Information
(Unaudited)

As of September 30, 2010 and December 31, 2009
and for the three and nine months ended
September 30, 2010 and 2009

INDEX OF ABBREVIATIONS

AG	Attorney General of Kentucky
ARO	Asset Retirement Obligation
ASC	Accounting Standards Codification
BART	Best Available Retrofit Technology
CAIR	Clean Air Interstate Rule
CAMR	Clean Air Mercury Rule
CATR	Clean Air Transport Rule
CCN	Certificate of Public Convenience and Necessity
Clean Air Act	The Clean Air Act, as amended in 1990
CMRG	Carbon Management Research Group
Companies	KU and LG&E
Company	KU
DSM	Demand Side Management
ECR	Environmental Cost Recovery
EEI	Edison Electric Institute
EKPC	East Kentucky Power Cooperative, Inc.
E.ON	E.ON AG
E.ON U.S.	E.ON U.S. LLC
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)
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
LG&E	Louisville Gas and Electric Company
MISO	Midwest Independent Transmission System Operator, Inc.
MMBtu	Million British thermal units
Moody's	Moody's Investors Service, Inc.
Mw	Megawatts
Mwh	Megawatt hours
NAAQS	National Ambient Air Quality Standards
NOV	Notice of Violation
NOx	Nitrogen Oxide
OMU	Owensboro Municipal Utilities
OVEC	Ohio Valley Electric Corporation
PPL	PPL Corporation
S&P	Standard & Poor's Ratings Services
SCR	Selective Catalytic Reduction
SERC	SERC Reliability Corporation
Servco	LG&E and KU Services Company (formerly E.ON U.S. Services Inc.)
SIP	State Implementation Plan
SO_2	Sulfur Dioxide
TC2	Trimble County Unit 2
Virginia Commission	Virginia State Corporation Commission

Kentucky Utilities Company
Condensed Financial Statements and Additional Information
(Unaudited)
As of September 30, 2010 and December 31, 2009
and for the three and nine months ended
September 30, 2010 and 2009

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PRICEWATERHOUSECOOPERS

PricewaterhouseCoopers LLP
500 West Main Street
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Report of Independent Accountants

To Shareholder of Kentucky Utilities Company:

We have reviewed the accompanying condensed balance sheet of Kentucky Utilities Company as of September 30, 2010, and the related condensed statements of income and comprehensive income, and of retained earnings for the three-month and nine-month periods ended September 30, 2010 and 2009 and the condensed statement of cash flows for the nine-month periods ended September 30, 2010 and 2009. This condensed interim financial information is the responsibility of the Company's management.

We conducted our review in accordance with standards established by the American Institute of Certified Public Accountants. A review of interim financial information consists principally of applying analytical procedures and making inquiries of persons responsible for financial and accounting matters. It is substantially less in scope than an audit conducted in accordance with auditing standards generally accepted in the United States of America, the objective of which is the expression of an opinion regarding the financial information taken as a whole. Accordingly, we do not express such an opinion.

Based on our review, we are not aware of any material modifications that should be made to the accompanying condensed interim financial information for it to be in conformity with accounting principles generally accepted in the United States of America.

We have previously audited, in accordance with auditing standards generally accepted in the United States of America, the balance sheet of Kentucky Utilities Company as of December 31, 2009, and the related statements of income, retained earnings, and of cash flows for the year then ended (not presented herein), and in our report dated March 19, 2010, we expressed an unqualified opinion on those financial statements. In our opinion, the information set forth in the accompanying condensed balance sheet information as of December 31, 2009, is fairly stated in all material respects in relation to the balance sheet from which it has been derived.

PricewaterhouseCoopers LLP

October 29, 2010

Kentucky Utilities Company
Condensed Statements of Income
(Unaudited)
(Millions of $)

	Three Months Ended September 30, 2010	Three Months Ended September 30, 2009	Nine Months Ended September 30, 2010	Nine Months Ended September 30, 2009
Operating revenues (Note 10)	$ 416	$ 341	$ 1,146	$ 1,009
Operating expenses:				
Fuel for electric generation	146	114	391	329
Power purchased (Note 10)	41	47	135	154
Other operation and maintenance expenses	86	22	251	230
Depreciation, accretion and amortization	38	33	106	99
Total operating expenses	311	216	883	812
Operating income	105	125	263	197
Interest expense (Note 8)	2	2	5	5
Interest expense to affiliated companies (Notes 8 and 10)	18	18	55	51
Other income (expense) – net	1	-	2	7
Income before income taxes	86	105	205	148
Income tax expense (Note 7)	32	39	76	49
Net income	$ 54	$ 66	$ 129	$ 99

The accompanying notes are an integral part of these condensed financial statements.

Kentucky Utilities Company
Condensed Statements of Comprehensive Income
(Unaudited)
(Millions of $)

	Three Months Ended September 30, 2010	Three Months Ended September 30, 2009	Nine Months Ended September 30, 2010	Nine Months Ended September 30, 2009
Net income	$ 54	$ 66	$ 129	$ 99
Comprehensive income (loss) attributable to unconsolidated venture – net of tax benefit of $1, $0, $1 and $0, respectively	(2)	-	(2)	-
Comprehensive income	$ 52	$ 66	$ 127	$ 99

Condensed Statements of Retained Earnings
(Unaudited)
(Millions of $)

	Three Months Ended September 30, 2010	Three Months Ended September 30, 2009	Nine Months Ended September 30, 2010	Nine Months Ended September 30, 2009
Balance at beginning of period	$ 1,403	$ 1,228	$ 1,328	$ 1,195
Net income	54	66	129	99
	1,457	1,294	1,457	1,294
Cash dividends declared (Note 10)	(50)	-	(50)	-
Balance at end of period	$ 1,407	$ 1,294	$ 1,407	$ 1,294

The accompanying notes are an integral part of these condensed financial statements.

Kentucky Utilities Company
Condensed Balance Sheets
(Unaudited)
(Millions of $)

	September 30, 2010	December 31, 2009
Assets		
Current assets:		
Cash and cash equivalents	$ 2	$ 2
Accounts receivable – net:		
Customer – less reserves of $2 in 2010 and $1 in 2009	172	155
Affiliated companies	-	9
Other – less reserves of $2 in 2010 and 2009	28	18
Materials and supplies:		
Fuel (predominantly coal)	98	98
Other materials and supplies	42	39
Regulatory assets (Note 2)	14	32
Prepayments and other current assets	11	13
Total current assets	367	366
Investment in unconsolidated venture	12	12
Property, plant and equipment:		
Regulated utility plant – electric	5,426	4,892
Accumulated depreciation	(1,902)	(1,838)
Net regulated utility plant	3,524	3,054
Construction work in progress	946	1,257
Property, plant and equipment – net	4,470	4,311
Deferred debits and other assets:		
Regulatory assets (Note 2):		
Pension benefits	105	105
Other regulatory assets	110	117
Cash surrender value of key man life insurance	39	38
Other assets	7	7
Total deferred debits and other assets	261	267
Total assets	$ 5,110	$ 4,956

The accompanying notes are an integral part of these condensed financial statements.

Kentucky Utilities Company
Condensed Balance Sheets (continued)
(Unaudited)
(Millions of $)

	September 30, 2010	December 31, 2009
Liabilities and Equity		
Current liabilities:		
Current portion of long-term debt (Notes 5 and 8)	$ 228	$ 228
Current portion of long-term debt to affiliated company (Note 5)	33	33
Notes payable to affiliated companies (Notes 8 and 10)	61	45
Accounts payable	105	107
Accounts payable to affiliated companies (Note 10)	71	88
Customer deposits	23	22
Regulatory liabilities (Note 2)	12	4
Other current liabilities	39	42
Total current liabilities	572	569
Long-term debt:		
Long-term debt (Notes 5 and 8)	123	123
Long-term debt to affiliated company (Notes 5, 8 and 10)	1,298	1,298
Total long-term debt	1,421	1,421
Deferred credits and other liabilities:		
Deferred income taxes	378	336
Accumulated provision for pensions and related benefits (Note 6)	160	160
Investment tax credits (Note 7)	104	104
Asset retirement obligations (Note 3)	59	34
Regulatory liabilities (Note 2):		
Accumulated cost of removal of utility plant	343	331
Other regulatory liabilities	24	29
Other liabilities	20	20
Total deferred credits and other liabilities	1,088	1,014
Common equity:		
Common stock, without par value –		
Authorized 80,000,000 shares, outstanding 37,817,878 shares	308	308
Additional paid-in capital	316	316
Accumulated other comprehensive loss	(2)	-
Retained earnings:		
Retained earnings	1,397	1,318
Undistributed earnings from unconsolidated venture	10	10
Total common equity	2,029	1,952
Total liabilities and equity	$ 5,110	$ 4,956

The accompanying notes are an integral part of these condensed financial statements.

Kentucky Utilities Company
Condensed Statements of Cash Flows
(Unaudited)
(Millions of $)

	For the Nine Months Ended September 30, 2010	2009
Cash flows from operating activities:		
Net income	$ 129	$ 99
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation, accretion and amortization	106	99
Deferred income taxes – net	42	48
Investment tax credits (Note 7)	-	17
Provision for pension and postretirement benefits	11	13
Undistributed earnings of unconsolidated venture	(4)	10
Other	1	3
Changes in current assets and liabilities:		
Accounts receivable	(6)	30
Materials and supplies	(3)	(21)
Regulatory assets and liabilities	26	(1)
Accounts payable	(20)	(4)
Accounts payable to affiliated companies	31	(8)
Other current assets and liabilities	-	(10)
Pension and postretirement funding (Note 6)	(17)	(17)
Other regulatory assets and liabilities	(3)	(64)
Other – net	7	(4)
Net cash provided by operating activities	300	190
Cash flows from investing activities:		
Construction expenditures	(218)	(378)
Purchases of assets from affiliate	(48)	-
Change in restricted cash	-	9
Net cash used in investing activities	(266)	(369)
Cash flows from financing activities:		
Borrowings from affiliated company (Note 8)	104	106
Repayments on borrowings from affiliated company (Note 8)	(88)	-
Payment of dividends (Note 10)	(50)	-
Capital contribution (Note 10)	-	75
Net cash (used in) provided by financing activities	(34)	181
Change in cash and cash equivalents	-	2
Cash and cash equivalents at beginning of period	2	2
Cash and cash equivalents at end of period	$ 2	$ 4

The accompanying notes are an integral part of these condensed financial statements.

Kentucky Utilities Company
Notes to Condensed Financial Statements
(Unaudited)

Note 1 – General

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 condensed financial statements include all adjustments, consisting only of normal recurring adjustments, necessary for fair statements of income, comprehensive income, and retained earnings, balance sheets, and statements of 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 condensed financial statements and notes should be read in conjunction with the Company's Financial Statements and Additional Information ("Annual Report") for the year ended December 31, 2009, including the audited financial statements and notes therein.

The December 31, 2009, condensed balance sheet included herein is derived from the December 31, 2009, audited balance sheet. Amounts reported in the condensed statements of income are not necessarily indicative of amounts expected for the respective annual periods due to the effects of seasonal temperature variations on energy consumption, regulatory rulings, the timing of maintenance on electric generating units, changes in mark-to-market valuations, changing commodity prices and other factors.

Certain reclassification entries have been made to the previous year's financial statements to conform to the 2010 presentation with no impact on total assets, liabilities and capitalization or previously reported net income and net cash flows.

PPL Acquisition

On April 28, 2010, E.ON U.S. announced that a Purchase and Sale Agreement (the "Agreement") had been entered into among E.ON US Investments, PPL and E.ON.

The Agreement provides for the sale of E.ON U.S. to PPL. Pursuant to the Agreement, at closing, PPL will acquire all of the outstanding limited liability company interests of E.ON U.S. for cash consideration of $2.6 billion. In addition, pursuant to the Agreement, PPL agreed to assume $764 million of pollution control bonds and medium term notes and to repay indebtedness owed by E.ON U.S. and its subsidiaries to E.ON US Investments and its affiliates. Such affiliate indebtedness is currently estimated to be $4.2 billion. The aggregate consideration payable by PPL on closing is currently estimated to be $7.6 billion (including the assumed indebtedness), subject to contractually agreed adjustments.

The transaction is subject to customary closing conditions, including the expiration or termination of the applicable waiting period under the Hart-Scott-Rodino Act, receipt of required regulatory approvals (including state regulators in Kentucky, Virginia and Tennessee, and the FERC) and the absence of injunctions or restraints imposed by governmental entities. As of October 26, 2010, all of the required regulatory approvals were received, and the transaction is expected to close on November 1, 2010.

Change of control and financing-related applications were filed on May 28, 2010, with the Kentucky Commission and on June 15, 2010, with the Virginia Commission and the Tennessee Regulatory Authority. An application with the FERC was filed on June 28, 2010. During the second quarter of 2010, a number of parties were granted intervenor status in the Kentucky Commission proceedings, and data request filings and responses occurred. Early termination of the Hart-Scott-Rodino waiting period was received on August 2, 2010.

A hearing in the Kentucky Commission proceedings was held on September 8, 2010, at which time a unanimous settlement agreement was presented. In the settlement, KU and LG&E commit that no base rate increases would take effect before January 1, 2013. The KU and LG&E rate increases that took effect on August 1, 2010, were not impacted by the settlement. Under the terms of the settlement, the Companies retain the right to seek approval for the deferral of "extraordinary and uncontrollable costs." Interim rate adjustments will continue to be permissible during that period for existing fuel, environmental and demand-side management cost trackers. The agreement also substitutes an acquisition savings shared deferral mechanism for the requirement that the Companies file a synergies plan with the Kentucky Commission. This mechanism, which will be in place until the earlier of five years or the first day of the year in which a base rate increase becomes effective, permits the Companies to earn up to a 10.75 percent return on equity. Any earnings above a 10.75 percent return on equity will be shared with customers on a 50%/50% basis. On September 30, 2010, the Kentucky Commission issued an Order approving the transfer of ownership of KU and LG&E via the acquisition of E.ON U.S. by PPL, incorporating the terms of the submitted settlement. On October 19, 2010 and October 21, 2010, respectively, Orders approving the acquisition of E.ON U.S. by PPL were received from the Virginia Commission and the Tennessee Regulatory Authority. The Commissions' Orders contained a number of other commitments with regard to operations, workforce, community involvement and other matters.

In mid-September 2010, KU and LG&E and other applicants in the FERC change of control proceeding reached an agreement with the protesters, whereby such protests have been withdrawn. The agreement, which has subsequently been filed for consideration with the FERC, includes various conditional commitments, such as a continuation of certain existing undertakings with protesters in prior cases, an agreement not to terminate certain KU municipal customer contracts prior to January 2017, an exclusion of any transaction-related costs from wholesale energy and tariff customer rates to the extent that the Company has agreed to not seek the same transaction-related cost from retail customers and agreements to coordinate with protesters in certain open or ongoing matters. A FERC Order approving the transaction was received on October 26, 2010.

On September 30, 2010, October 19, 2010 and October 21, 2010, respectively, KU received Kentucky Commission, Virginia Commission and Tennessee Regulatory Authority approvals to complete certain refinancing transactions in connection with the anticipated PPL acquisition and other business factors. Based on credit and financial market conditions, KU anticipates issuing up to $1.5 billion in first mortgage bonds, the proceeds of which will substantially be used to refund existing long-term intercompany debt. On October 29, 2010, as required by existing covenants, in connection with the anticipated issuance of any such secured debt, KU completed collateralization of certain outstanding pollution control bond debt series which were formerly unsecured. Pursuant to such collateralization, approximately $351 million in existing pollution control debt became collateralized debt, supported by a first mortgage lien. KU also anticipates replacing its $35 million bilateral line of credit with an unaffiliated institution by entering into a multi-year revolving credit facility with several financial institutions in an aggregate amount not to exceed $400 million. KU may complete these transactions, in whole or in part, during late 2010 and early 2011. See Note 8, Short-Term and Long-Term Debt, for further information regarding the refinancing, remarketing or conversion of existing pollution control debt.

Recent Accounting Pronouncements

Fair Value Measurements

In January 2010, the FASB issued guidance related to fair value measurement disclosures requiring separate disclosure of amounts of significant transfers in and out of level 1 and level 2 fair value measurements and separate information about purchases, sales, issuances, and settlements within level 3 measurements. This guidance is effective for the interim and annual reporting periods beginning after December 15, 2009, except for the disclosures about the roll-forward of activity in level 3 fair value measurements. Those disclosures are effective for fiscal years beginning after December 15, 2010, and for interim periods within those fiscal years. This guidance has no impact on the Company's results of operations, financial position, liquidity or disclosures.

Note 2 – Rates and Regulatory Matters

KU's Kentucky base rates are calculated based on a return on capitalization (common equity, long-term debt and notes payable) including certain regulatory adjustments to exclude non-regulated investments and environmental compliance plans recovered separately through the ECR mechanism. Currently, none of the regulatory assets or regulatory liabilities are excluded from the return on capitalization utilized in the calculation of Kentucky base rates; therefore, a return is earned on all Kentucky regulatory assets.

KU's Virginia base rates are calculated based on a return on rate base (net utility plant less deferred taxes and miscellaneous deductions). All regulatory assets and liabilities are excluded from the return on rate base utilized in the calculation of Virginia base rates.

For a description of each line item of regulatory assets and liabilities and for descriptions of certain matters which may not have undergone material changes relating to the period covered by this quarterly report, reference is made to Note 2, Rates and Regulatory Matters, of KU's Annual Report for the year ended December 31, 2009.

2010 Kentucky Rate Case

In January 2010, KU filed an application with the Kentucky Commission requesting an increase in electric base rates of approximately 12%, or $135 million annually, including an 11.5% return on equity. KU requested the increase, based on the twelve month test year ended October 31, 2009, to become effective on and after March 1, 2010. The requested rates were suspended until August 1, 2010. A number of intervenors entered the rate case, including the AG, certain representatives of industrial and low-income groups and other third parties, and submitted filings challenging the Company's requested rate increases, in whole or in part. A hearing was held on June 8, 2010. KU and all of the intervenors, except the AG, agreed to a stipulation providing for an increase in electric base rates of $98 million annually and filed a request with the Kentucky Commission to approve such settlement. An Order in the proceeding was issued in July 2010, approving all the provisions in the stipulation. The new rates became effective on August 1, 2010.

Virginia Rate Case

In June 2009, KU filed an application with the Virginia Commission requesting an increase in electric base rates for its Virginia jurisdictional customers in an amount of $12 million annually or approximately 21%. The proposed increase reflected a proposed rate of return on rate base of 8.586% based on a return on equity of 12%. During December 2009, KU and the Virginia Commission Staff agreed to a Stipulation and Recommendation authorizing base rate revenue increases of $11 million annually and a return on rate base of 7.846% based on a 10.5% return on common equity. A public hearing was held during January 2010. As permitted, pursuant to a Virginia Commission Order, KU elected to implement the proposed rates effective November 1, 2009, on an interim basis. In March 2010, the Virginia Commission issued an Order approving the stipulation, with the increased rates to be put into effect as of April 1, 2010. As part of the stipulation, KU refunded approximately $1 million in interim rate amounts in excess of the ultimate approved rates. During August 2010, a report was filed detailing the costs of the refunds, the accounts charged and details validating that all refunds have been applied.

FERC Wholesale Rate Case

In September 2008, KU filed an application with the FERC for increases in electric base rates applicable to wholesale power sales contracts or interchange agreements involving, collectively, twelve Kentucky municipalities. The application requested a shift from an all-in stated unit charge rate to an unbundled formula rate, including an annual adjustment mechanism. In May 2009, the FERC issued an Order approving a settlement among the parties in the case, incorporating increases of approximately 3% from prior rates and a return on equity of 11%. In May 2010, KU submitted to the FERC the proposed current annual adjustment to the formula rate. This updated rate became effective on July 1, 2010, subject to certain review procedures by the wholesale requirements customers and the FERC, including potential refunds in the case of disallowed costs or charges.

By mutual agreement, the parties' settlement of the 2008 application left outstanding the issue of whether KU must allocate to the municipal customers a portion of renewable resources it may be required to procure on behalf of its retail ratepayers. In August 2009, the FERC accepted the issue for briefing and the parties completed briefing submissions during 2009. An Order was issued by the FERC in July 2010, indicating that KU is not required to allocate a portion of any renewable resources to the twelve municipalities, thus resolving the remaining issue.

Regulatory Assets and Liabilities

The following regulatory assets and liabilities were included in KU's balance sheets as of:

(in millions)	September 30, 2010	December 31, 2009
Current regulatory assets:		
Storm restoration (a)	$ 6	$ -
FAC (b)	4	1
ECR (b)	-	28
MISO exit (a)	1	2
Other (c)	3	1
Total current regulatory assets	$ 14	$ 32

	September 30, 2010	December 31, 2009
Non-current regulatory assets:		
Pension benefits (d)	$ 105	$ 105
Other non-current regulatory assets:		
Storm restoration (a)	52	59
ARO (e)	34	30
Unamortized loss on bonds (a)	12	12
MISO exit (a)	4	9
Other (c)	8	7
Subtotal other non-current regulatory assets	110	117
Total non-current regulatory assets	$ 215	$ 222
Current regulatory liabilities:		
ECR	$ 6	$ -
DSM	4	3
Other (f)	2	1
Total current regulatory liabilities	$ 12	$ 4
Non-current regulatory liabilities:		
Accumulated cost of removal of utility plant	$ 343	$ 331
Other non-current regulatory liabilities:		
Deferred income taxes – net	8	9
Postretirement benefits	9	9
MISO exit	1	4
Other (f)	6	7
Subtotal other non-current regulatory liabilities	24	29
Total non-current regulatory liabilities	$ 367	$ 360

(a) These regulatory assets are recovered through base rates.
(b) The FAC and ECR regulatory assets have separate recovery mechanisms with recovery within twelve months.
(c) Other regulatory assets:
- Other current and non-current regulatory assets, including the CMRG and KCCS contributions, an EKPC FERC transmission settlement agreement and rate case expenses, are recovered through base rates.
- The current portion of the unamortized loss on bonds is recovered through base rates.
- KU generally recovers the FERC jurisdictional portion of the EKPC FERC transmission settlement agreement included in current and non-current regulatory assets in the application of the annual Open Access Transmission Tariff formula rate updates.
- Recovery of the FERC jurisdictional pension expense in non-current regulatory assets will be requested in a future FERC rate case.

(d) KU generally recovers this asset through pension expense included in the calculation of base rates.

(e) When an asset with an ARO is retired, the related ARO regulatory asset will be offset against the associated ARO regulatory liability, ARO asset and ARO liability.
(f) Other current and non-current regulatory liabilities includes the Virginia levelized fuel factor regulatory liability, ARO liabilities and a change in accounting method for FERC jurisdictional spare parts. ARO liabilities are established from the removal costs accrued through depreciation under regulatory accounting for assets associated with AROs.

Storm Restoration

In January 2009, a significant ice storm passed through KU's service territory causing approximately 199,000 customer outages and was followed closely by a severe wind storm in February 2009, which caused approximately 44,000 customer outages. KU incurred $57 million in incremental operation and maintenance expenses and $33 million in capital expenditures related to the restoration following the two storms. The Company filed an application with the Kentucky Commission in April 2009, requesting approval to establish a regulatory asset and defer for future recovery approximately $62 million in incremental operation and maintenance expenses related to the storm restoration. In September 2009, the Kentucky Commission issued an Order allowing the Company to establish a regulatory asset of up to $62 million based on its actual costs for storm damages and service restoration due to the January and February 2009 storms. In September 2009, the Company established a regulatory asset of $57 million for actual costs incurred. The Company received approval in its 2010 base rate case to recover this asset over a ten year period beginning August 1, 2010.

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. In December 2008, the Company established a regulatory asset of $2 million for actual costs incurred. The Company received approval in its 2010 base rate case to recover this asset over a ten year period beginning August 1, 2010.

FAC

In August 2010, the Kentucky Commission initiated a six-month review of KU's FAC mechanism for the expense period ended April 2010. An order is expected by the end of the year.

In February 2010, KU filed an application with the Virginia Commission seeking approval of a decrease in its fuel cost factor beginning with service rendered in April 2010. An Order was issued in April 2010, resulting in an agreed upon decrease of 23% from the fuel factor in effect for April 2009 through March 2010.

In January 2010, the Kentucky Commission initiated a six-month review of KU's FAC mechanism for the expense period ended August 2009. In May 2010, an Order was issued approving the charges and credits billed through the FAC during the review period.

ECR

In July 2010, the Kentucky Commission initiated a six-month review of KU's environmental surcharge for the billing period ending April 2010. An order is expected in the fourth quarter of 2010.

In January 2010, the Kentucky Commission initiated a six-month review of KU's environmental surcharge for the billing period ending October 2009. In May 2010, an Order was issued approving the amounts billed through the ECR during the six-month period and the rate of return on capital and allowing recovery of the under-recovery position in subsequent monthly filings.

In June 2009, the Company filed an application for a new ECR plan with the Kentucky Commission seeking approval to recover investments in environmental upgrades and operations and maintenance costs at the Company's generating facilities. During 2009, KU reached a unanimous settlement with all parties to the case, and the Kentucky Commission issued an Order approving KU's application. Recovery on customer bills through the monthly ECR surcharge for these projects began with the February 2010 billing cycle. At December 31, 2009, the Company had a regulatory asset of $28 million, which changed to a regulatory liability in the first quarter of 2010, as a result of these roll-in adjustments to base rates. At September 30, 2010, the regulatory liability balance was $6 million.

MISO

In August 2010, the FERC issued three Orders accepting most facets of several MISO Revenue Sufficiency Guarantee ("RSG") compliance filings. The FERC ordered the MISO to issue refunds for RSG charges that were imposed by the MISO on the assumption that there were rate mismatches for the period beginning November 5, 2007 through the present. There is no financial statement impact to the Company from this Order, as the MISO had anticipated that the FERC would require these refunds and had preemptively included them in the resettlements paid in 2009. The FERC denied MISO's proposal to exempt certain resources from RSG charges, effective prospectively. The FERC accepted portions and rejected portions of the MISO's proposed RSG rate Redesign Proposal, which will be effective when the software is ready for implementation subject to further compliance filings. The impact of the Redesign Proposal on the Company cannot be estimated at this time.

<u>Other Regulatory Matters</u>

TC2 Depreciation

In August 2009, the Companies jointly filed an application with the Kentucky Commission to approve new common depreciation rates for applicable jointly-owned TC2-related generating, pollution control and other plant equipment and assets. During December 2009, the Kentucky Commission extended the data discovery process through January 2010, and authorized the Companies on an interim basis to begin using the depreciation rates for TC2 as proposed in the application. In March 2010, the Kentucky Commission issued a final Order approving the use of the proposed depreciation rates on a permanent basis.

TC2 Transmission Matters

KU's and LG&E's CCN for a transmission line associated with the TC2 construction has been challenged by certain property owners in Hardin County, Kentucky. In August 2006, the Companies obtained a successful dismissal of the challenge at the Franklin County Circuit Court, which was reversed by the Kentucky Court of Appeals in December 2007. In April 2009, the Kentucky Supreme Court granted KU's and LG&E's motion for discretionary review of the Court of Appeals' decision. In August 2010, the Kentucky Supreme Court issued an Order reversing the decision of the Kentucky Court of Appeals and reinstating the Franklin County Circuit Court's dismissal of the property owners' challenge to KU's and LG&E's CCN.

During 2008, KU obtained various successful rulings at the Hardin County Circuit Court confirming its condemnation rights. In August 2008, several landowners appealed such rulings to the Kentucky Court of Appeals. In May 2010, the Kentucky Court of Appeals issued an Order affirming the Hardin Circuit Court's finding that KU had the right to condemn easements on the properties. In May 2010, the landowners filed a petition for reconsideration with the Court of Appeals. In July 2010, the Court of Appeals denied that petition. In August, 2010, the landowners filed for discretionary review of that denial by the Kentucky Supreme Court.

In a separate proceeding, certain Hardin County landowners filed an action in federal district court in Louisville, Kentucky against the U.S. Army challenging the same transmission line claiming that certain Fort Knox-related sections of the line failed to comply with certain National Historic Preservation Act procedural requirements. In October 2009, the federal court granted the defendants' motion for summary judgment and dismissed the plaintiffs' claims. During November 2009, the petitioners filed submissions for review of the decision with the 6th Circuit Court of Appeals. In May 2010, the appellate court issued an order approving the plaintiffs' voluntary withdrawal of their appeals.

Consistent with the regulatory authorizations and relevant legal proceedings, the Companies have completed construction activities on temporary or permanent transmission line segments. During the second quarter of 2010, the Companies placed into operation an appropriate combination of permanent and temporary sections of the transmission line. While the Companies are not currently able to predict the ultimate outcome and possible financial effects of the remaining legal proceedings, the Companies do not believe the matter involves relevant or continuing risks to operations.

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 Regional Reliability Organizations ("RROs") by the North American Electric Reliability Corporation ("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 on the circumstances of the violation. The Companies are members of SERC, which acts as KU's and LG&E's RRO. During December 2009, SERC and the Companies agreed to settlements involving penalties totaling less than $1 million for each utility related to their self-reports during June and October 2008, concerning possible violations of standards. During December 2009 and April, July and August 2010, the Companies submitted ten self-reports relating to various standards, which self-reports remain in the early stages of RRO review, and therefore, the Companies are unable to estimate the outcome of these matters.

Mandatory reliability standard settlements commonly also include non-penalty elements, including compliance steps and mitigation plans. Settlements with SERC proceed to NERC and FERC review before becoming final. While the Companies believe they are in compliance with the mandatory reliability standards, events of potential non-compliance may be identified from time-to-time. The Companies cannot predict such potential violations or the outcome of the self-reports described above.

Note 3 – Asset Retirement Obligation

A summary of KU's net ARO assets, ARO liabilities and regulatory assets established under the asset retirement and environmental obligations guidance of the FASB ASC follows:

(in millions)	ARO Net Assets	ARO Liabilities	Regulatory Assets
As of December 31, 2009	$ 4	$ (34)	$ 30
ARO accretion	-	(2)	2
ARO revaluation	21	(23)	2
As of September 30, 2010	$ 25	$ (59)	$ 34

As of September 30, 2010, the Company performed a revaluation of its AROs as a result of recently proposed environmental legislation and improved ability to forecast asset retirement costs due to recent construction and retirement activity.

Pursuant to regulatory treatment prescribed under the regulated operations guidance of the FASB ASC, an offsetting regulatory credit was recorded in depreciation and amortization in the income statement of $2 million for the nine months ended September 30, 2010 for the ARO accretion and depreciation expense. KU's AROs are primarily related to the final retirement of assets associated with generating units.

KU transmission and distribution lines largely operate under perpetual property easement agreements which do not generally require restoration on removal of the property. Therefore, under the asset retirement and environmental obligations guidance of the FASB ASC, no material asset retirement obligations are recorded for transmission and distribution assets.

Note 4 – Derivative Financial Instruments

KU is subject to interest rate and commodity price risk related to on-going business operations. It currently manages these risks using derivative instruments, including swaps and forward contracts. The Company'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 September 30, 2010, a 100 basis point change in the benchmark rate on KU's variable rate debt, not effectively hedged by an interest rate swap, would impact pre-tax interest expense by $4 million annually. Although the Company's policies allow for the use of interest rate swaps, as of September 30, 2010 and December 31, 2009, KU had no interest rate swaps outstanding.

The Company does not net collateral against derivative instruments.

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 the derivatives and hedging topic of the FASB ASC.

Energy trading and risk management contracts are valued using prices based on active trades from Intercontinental Exchange Inc. In the absence of a traded price, midpoints of the best bids and offers are the primary determinants of valuation. When sufficient trading activity is unavailable, other inputs 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. 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 2010 or 2009. Changes in market pricing, interest rate and volatility assumptions were made during both years.

KU's financial assets and liabilities as of September 30, 2010 and December 31, 2009, arising from energy trading and risk management contracts not designated as hedging instruments accounted for at fair value total less than $1 million and are recorded in prepayments and other current assets and other current liabilities, respectively.

The Company maintains credit policies intended to minimize credit risk in wholesale marketing and trading activities by assessing the creditworthiness of potential counterparties prior to entering into transactions with them and continuing to evaluate their creditworthiness once transactions have been initiated. To further mitigate credit risk, KU seeks to enter into netting agreements or require cash deposits, letters of credit and parental company guarantees as security from counterparties. The Company uses S&P, Moody's and definitive qualitative and quantitative data to assess the financial strength of counterparties on an on-going basis. If no external rating exists, KU assigns an internally generated rating for which it sets appropriate risk parameters. As risk management contracts are valued based on changes in market prices of the related commodities, credit exposures are revalued and monitored on a daily basis. At September 30, 2010, 100% of the trading and risk management commitments were with counterparties rated BBB-/Baa3 equivalent or better. The Company has reserves 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 September 30, 2010 and December 31, 2009, counterparty credit reserves related to energy trading and risk management contracts were less than $1 million.

The net volume of electricity based financial derivatives outstanding at September 30, 2010 and December 31, 2009, was zero and 43,400 Mwhs, respectively. No cash collateral related to the energy trading and risk management contracts was required at September 30, 2010. Cash collateral related to the energy trading and risk management contracts was less than $1 million at December 31, 2009. Cash collateral related to the energy trading and risk management contracts is categorized as other accounts receivable in the accompanying balance sheets.

KU manages the price risk of its estimated future excess economic generation capacity using market-traded forward contracts. Hedge accounting treatment has not been elected for these transactions, and therefore realized and unrealized gains and losses are included in the statements of income.

The following tables present the effect of derivatives not designated as hedging instruments on income:

(in millions)		Three Months Ended September 30,	
Loss Recognized in Income	Location	2010 (a)	2009
Unrealized loss	Electric revenues	$ -	$ (3)

		Nine Months Ended September 30,	
Loss Recognized in Income	Location	2010 (a)	2009
Unrealized loss	Electric revenues	$ -	$ (1)

(a) Unrealized loss was less than $1 million

Net realized gains were less than $1 million in the three and nine months ended September 30, 2010 and 2009, respectively.

Credit Risk Related Contingent Features

Certain of the Company's derivative instruments contain provisions that require the Company to provide immediate and on-going collateralization on derivative instruments in net liability positions based on the Company's credit ratings from each of the major credit rating agencies. At September 30, 2010, there are no energy trading and risk management contracts with credit risk related contingent features that are in a liability position and no collateral posted in the normal course of business. At September 30, 2010, a one notch downgrade of the Company's credit rating would have no effect on the energy trading and risk management contracts or collateral required.

Note 5 – Fair Value Measurements

KU adopted the fair value guidance in the FASB ASC in two phases. Effective January 1, 2008, the Company adopted it for all financial instruments and non-financial instruments accounted for at fair value on a recurring basis, and January 1, 2009, the Company adopted it for all non-financial instruments accounted for at fair value on a non-recurring basis. The FASB ASC guidance clarifies that fair value is an exit price, representing the amount that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants. As such, fair value is a market-based measurement that should be determined based on assumptions that market participants would use in pricing an asset or a liability. As a basis for considering such assumptions, the FASB ASC guidance establishes a three-tier value hierarchy, which prioritizes the inputs used in the valuation methodologies in measuring fair value.

The carrying values and estimated fair values of KU's non-trading instruments:

	September 30, 2010		December 31, 2009	
(in millions)	Carrying Value	Fair Value	Carrying Value	Fair Value
Long-term bonds (including current portion of $228 million)	$ 351	$ 352	$ 351	$ 351
Long-term debt to affiliated company (including current portion of $33 million)	1,331	1,527	1,331	1,401

The long-term bond valuations reflect prices quoted by investment banks, which are active in the market for these debt instruments. The fair value of the long-term debt due to affiliated company is determined using an internal valuation model that discounts the future cash flows of each loan at current market rates as 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 has classified the applicable financial assets and liabilities that are accounted for at fair value into the three levels of the fair value hierarchy, as defined by the fair value measurements and disclosures topic of the FASB ASC, as follows:

- Level 1 – Observable inputs that reflect quoted prices (unadjusted) for identical assets or liabilities in active markets
- Level 2 – Include other inputs that are directly or indirectly observable in the marketplace
- Level 3 – Unobservable inputs which are supported by little or no market activity

The fair value hierarchy also requires an entity to maximize the use of observable inputs and minimize the use of unobservable inputs when measuring fair value.

The Company classifies its derivative cash collateral balances within level 1 based on the funds being held in a demand deposit account. The Company classifies its derivative energy trading and risk management contracts within level 2 because it values them using prices actively quoted for proposed or executed transactions, quoted by brokers or observable inputs other than quoted prices.

KU's financial assets and liabilities as of September 30, 2010 and December 31, 2009, arising from energy trading and risk management contracts accounted for at fair value on a recurring basis total less than $1 million. No cash collateral related to the energy trading and risk management contracts was required at September 30, 2010. Cash collateral related to the energy trading and risk management contracts was less than $1 million at December 31, 2009.

There were no level 3 measurements for the periods ending September 30, 2010 and December 31, 2009.

Note 6 – Pension and Other Postretirement Benefit Plans

Net Periodic Benefit Costs

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 Servco employees who are providing services to KU. The Servco costs are allocated to KU based on employees' labor charges and are approximately 53% and 51% of Servco costs for September 30, 2010 and 2009, respectively.

(in millions)

	Pension Benefits Three Months Ended September 30,					
	2010			2009		
	KU	Servco Allocation to KU	Total KU	KU	Servco Allocation to KU	Total KU
Service cost	$ 2	$ 1	$ 3	$ 2	$ 1	$ 3
Interest cost	4	2	6	4	2	6
Expected return on plan assets	(5)	(2)	(7)	(3)	(1)	(4)
Amortization of prior service cost	-	1	1	-	-	-
Amortization of actuarial loss	2	1	3	2	1	3
Net periodic benefit cost	$ 3	$ 3	$ 6	$ 5	$ 3	$ 8

	Other Postretirement Benefits Three Months Ended September 30,					
	2010			2009		
	KU	Servco Allocation to KU(a)	Total KU	KU	Servco Allocation to KU(a)	Total KU
Interest cost	$ 2	$ -	$ 2	$ 1	$ -	$ 1
Net periodic benefit cost	$ 2	$ -	$ 2	$ 1	$ -	$ 1

(a) amounts are less than $1 million

Pension Benefits Nine Months Ended September 30,						
	2010			2009		
	KU	Servco Allocation to KU	Total KU	KU	Servco Allocation to KU	Total KU
Service cost	$ 5	$ 4	$ 9	$ 4	$ 4	$ 8
Interest cost	14	6	20	13	5	18
Expected return on plan assets	(13)	(5)	(18)	(10)	(4)	(14)
Amortization of prior service cost	-	1	1	1	1	2
Amortization of actuarial loss	5	2	7	6	2	8
Net periodic benefit cost	$ 11	$ 8	$ 19	$ 14	$ 8	$ 22

Other Postretirement Benefits Nine Months Ended September 30,						
	2010			2009		
	KU	Servco Allocation to KU	Total KU	KU	Servco Allocation to KU	Total KU
Service cost	$ 1	$ 1	$ 2	$ 1	$ 1	$ 2
Interest cost	4	-	4	3	-	3
Expected return on plan assets	(1)	-	(1)	-	-	-
Amortization of transitional obligation	1	-	1	1	-	1
Net periodic benefit cost	$ 5	$ 1	$ 6	$ 5	$ 1	$ 6

Contributions

In January 2010, KU and Servco made discretionary pension plan contributions of $13 million and $9 million, respectively. The amount of future contributions to the pension plan will depend on the actual return on plan assets and other factors, but the Company's intent is to fund the pension plan in a manner consistent with the requirements of the Pension Protection Act of 2006.

Through September 2010, KU made contributions to other postretirement benefit plans totaling $4 million. An additional contribution totaling $1 million was made in October. The Company anticipates further funding to match the annual postretirement expense and funding the 401(h) plan up to the maximum amount allowed by law.

Health Care Reform

In March 2010, Health Care Reform (the Patient Protection and Affordable Care Act of 2010) was signed into law. Many provisions of Health Care Reform do not take effect for an extended period of time, and many aspects of the law which are currently unclear or undefined will likely be clarified in future regulations.

During each of the three and nine months ended September 30, 2010, KU recorded an income tax expense of less than $1 million, to recognize the impact of the elimination of the tax deduction related to the Medicare Retiree Drug Subsidy that becomes effective in 2013.

Specific provisions within Health Care Reform that may impact KU include:

- Beginning in 2011, requirements extend dependent coverage up to age 26, remove the $2 million lifetime maximum and eliminate cost sharing for certain preventative care procedures.
- Beginning in 2018, a potential excise tax is expected on high-cost plans providing health coverage that exceeds certain thresholds.

KU continues to evaluate all implications of Health Care Reform on its benefit programs but at this time cannot predict the significance of those implications.

Note 7 – 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. The Company also files income tax returns in various state jurisdictions. While 2007 and later years are open under the federal statute of limitations, Revenue Agent Reports for 2006-2008 have been received from the IRS, effectively closing these years to additional audit adjustments. Tax years beginning with 2007 were examined under an IRS pilot program named "Compliance Assurance Process" ("CAP"). This program accelerates the IRS' review to begin during the year applicable to the return and ends 90 days after the return is filed. For 2008, the IRS allowed additional deductions in connection with the Company's application for a change in repair deductions and disallowed some of the bonus depreciation claimed on the original return. The net temporary tax impact for the Company was $12 million and was recorded in the second quarter of 2010. Tax years 2009 and 2010 are also being examined under CAP. The 2009 federal return was filed in the third quarter, and the IRS issued a Partial Acceptance Letter with the 2009 return. The IRS is continuing to review bonus depreciation, storms and other repairs. No material impact is expected from the IRS review. For the tax year 2010, no material items have been raised by the IRS at this time.

Additions and reductions of uncertain tax positions during 2010 and 2009 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. If recognized, the less than $1 million of unrecognized tax benefits would reduce the effective income tax rate.

The amount KU recognized as interest expense and interest accrued related to unrecognized tax benefits was less than $1 million as of September 30, 2010 and December 31, 2009. The interest expense and interest accrued is based on IRS and Kentucky Department of Revenue large corporate interest rates for underpayment of taxes. At the date of adoption, the Company accrued less than $1 million in interest expense on uncertain tax positions. KU records the interest as interest expense and penalties as operating expenses in the income statement and accrued expenses in the balance sheet, on a pre-tax basis. No penalties were accrued by the Company through September 30, 2010.

In June 2006, the Companies 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 was selected to receive $101 million in tax credits. A final IRS certification required to obtain the investment tax credits was received in August 2007. In September 2007, KU received an Order from the Kentucky Commission approving the accounting of the investment tax credits, which includes a full depreciation basis adjustment for the amount of the credits. Based on eligible construction expenditures incurred, KU recorded investment tax credits of $6 and $17 million during the three and nine months ended September 30, 2009, decreasing current federal income taxes. As of December 31, 2009 KU had recorded its maximum credit of $101 million. The income tax expense impact from amortizing these credits over the life of the related property will begin when the facility is placed in service, which is expected to occur by year end.

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. The plaintiffs voluntarily dismissed their complaint in August 2010.

A reconciliation of differences between the income tax expense at the statutory U.S. federal income tax rate and the Company's actual income tax expense follows:

(in millions)	Three Months Ended September 30, 2010	Three Months Ended September 30, 2009	Nine Months Ended September 30, 2010	Nine Months Ended September 30, 2009
Statutory federal income tax expense	$ 30	$ 37	$ 72	$ 52
State income taxes – net of federal benefit	3	4	8	4
Dividends received deduction related to EEI investment	-	-	-	(3)
Other differences – net	(1)	(2)	(4)	(4)
Income tax expense	$ 32	$ 39	$ 76	$ 49
Effective income tax rate	37.2%	37.1%	37.1%	33.1%

The amounts shown in the table above are rounded to the nearest $1 million; however, the effective income tax rates are based on actual underlying amounts. Other differences – net includes the qualified production activities deduction and excess deferred taxes on depreciation.

The effective tax rate for the nine months ended September 2010 was higher than the rate for the nine months ended 2009 due to state income taxes – net of federal benefit being lower due to a coal credit recorded in 2009 and a lower dividends received deduction primarily due to the lack of EEI dividends in 2010.

Note 8 – Short-Term and Long-Term Debt

KU's long-term debt includes $228 million of pollution control bonds that are classified as current portion of long-term debt 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:

(in millions)		
Mercer Co. 2000 Series A, due May 1, 2023, variable %	$	13
Carroll Co. 2002 Series A, due February 1, 2032, variable %		21
Carroll Co. 2002 Series B, due February 1, 2032, variable %		2
Carroll Co. 2008 Series A, due February 1, 2032, variable %		78
Mercer Co. 2002 Series A, due February 1, 2032, variable %		8
Muhlenberg Co. 2002 Series A, due February 1, 2032, variable %		2
Carroll Co. 2004 Series A, due October 1, 2034, variable %		50
Carroll Co. 2006 Series B, due October 1, 2034, variable %		54
	$	228

The average annualized interest rates for these bonds follow:

	September 30, 2010	September 30, 2009
Three months ended	0.37%	0.51%
Nine months ended	0.36%	0.65%

Pollution control bonds are obligations of KU issued in connection with tax-exempt pollution control bonds issued by counties in Kentucky. A loan agreement obligates the Company to make debt service payments to the counties that equate to the debt service due from the counties on the related pollution control bonds. The loan agreement is an unsecured obligation of the Company. Debt issuance expense is capitalized in either regulatory assets or current or long-term other assets and amortized over the lives of the related bond issues, consistent with regulatory practices.

In October 2010, KU's pollution control bonds were converted from unsecured debt to debt which is collateralized by first mortgage bonds. Also in October 2010, one national rating agency revised downward the short-term credit rating of the pollution control bonds and the Company's issuer rating as a result of the pending acquisition by PPL.

Several of the KU pollution control bonds are insured by monoline bond insurers whose ratings have been reduced due to exposures relating to insurance of sub-prime mortgages. At September 30, 2010, 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. Since 2008, the Company experienced "failed auctions" when there were insufficient bids for the bonds. When a failed auction occurs, the interest rate is set pursuant to a formula stipulated in the indenture.

The average annualized interest rates on the auction rate bonds follow:

	September 30, 2010	September 30, 2009
Three months ended	0.61%	0.34%
Nine months ended	0.50%	0.51%

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 June 2009, one national rating agency downgraded the credit rating of an insurer of the Company's bonds. As a result, the national rating agency downgraded the rating on the Carroll County 2002 Series C bond. The national agency's rating of this bond is now based on the rating of the Company rather than the rating of the insurer since the Company's rating is higher.

The Company 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
September 30, 2010	$ 400	$ 61	$ 339	0.28%
December 31, 2009	$ 400	$ 45	$ 355	0.20%

E.ON U.S. maintained revolving credit facilities totaling $313 million at September 30, 2010 and December 31, 2009, to ensure funding availability for the money pool. At September 30, 2010, one facility, totaling $150 million, was with E.ON North America, Inc. while the remaining line, totaling $163 million, was with Fidelia; both are affiliated companies. The balances are as follows:

(in millions)	Total Available	Amount Outstanding	Balance Available	Average Interest Rate
September 30, 2010	$ 313	$ 181	$ 132	1.44%
December 31, 2009	$ 313	$ 276	$ 37	1.25%

As of September 30, 2010, the Company maintained a $35 million bilateral line of credit, maturing in June 2012, with an unaffiliated financial institution. At September 30, 2010, there was no balance outstanding under this facility. The Company also maintains letter of credit facilities that support $195 million of the $228 million of bonds that can be put back to the Company. Should the holders elect to put the bonds back and they cannot be remarketed, the letter of credit would fund the investor's payment.

There were no redemptions or issuances of long-term debt year-to-date through September 30, 2010. KU was in compliance with all debt covenants at September 30, 2010 and December 31, 2009. See Note 1, General, for certain debt refinancing and associated transactions which are anticipated by KU in connection with the PPL acquisition and Note 10, Related Party Transactions, for long-term debt payable to affiliates.

Note 9 – Commitments and Contingencies

Except as may be discussed in this quarterly report (including Note 2, Rates and Regulatory Matters), material changes have not occurred in the current status of various commitments or contingent liabilities from that discussed in the Company's Annual Report for the year ended December 31, 2009 (including, but not limited to Note 2, Rates and Regulatory Matters; Note 9, Commitments and Contingencies; and Note 12, Subsequent Events, contained therein). See the Company's Annual Report regarding such commitments or contingencies.

Letters of Credit

KU has provided letters of credit as of September 30, 2010 and December 31, 2009, for on-balance sheet obligations totaling $198 million to support bonds of $195 million and a letter of credit for off-balance sheet obligations totaling less than $1 million to support certain obligations related to workers' compensation.

Owensboro Contract Litigation and Contract Termination

In May 2004, the City of Owensboro, Kentucky and OMU commenced a suit against KU concerning a long-term power supply contract (the "OMU Agreement") with KU. In May 2009, KU and OMU executed a settlement agreement resolving the matter on a basis consistent with prior court rulings, and the Company has received the agreed settlement amounts. Pursuant to the settlement's operation, the OMU agreement terminated in May 2010. In connection with such termination, KU has recorded a net receivable totaling $4 million reflecting its estimate of remaining adjustments concerning prior accruals. The parties are engaged in discussions to resolve those remaining adjustments.

Construction Program

KU had approximately $167 million of commitments in connection with its construction program at September 30, 2010.

In June 2006, the Companies 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. During 2009 and 2010, the Companies received several contractual notices from the TC2 construction contractor asserting historical force majeure and excusable event claims for a number of adjustments to the contract price, construction schedule, commercial operations date, liquidated damages or other relevant provisions. In September 2010, the Companies and construction contractor agreed to a settlement to resolve certain force majeure and excusable event claims occurring through July 2010, under the TC2 construction contract, which settlement provided for a limited, negotiated extension of the contractual commercial operations date and/or relief from liquidated damages calculations. During commissioning activities in the second and third quarters, separate delays have occurred related to burner malfunctions and an excitation transformer failure. Certain temporary or permanent repairs for both matters have been completed, are underway or are planned for appropriate future outage periods. Commissioning steps resumed in October 2010, and a revised commercial operations date is currently expected by year end. The parties are analyzing the treatment of these additional delays under the liquidated damages provisions of the construction agreement. The Companies cannot currently estimate the ultimate outcome of these matters, including the extent, if any, that such outcome may result in materially increased costs for the construction of TC2, further changes in the TC2 construction completion or commercial operation dates or potential effects on levels of power purchases or wholesale sales due to such changed dates.

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. In September 2007, the Secretary of the Kentucky Environmental and Public Protection Cabinet issued a final Order upholding the permit. The environmental groups petitioned the EPA to object to the state permit and subsequent permit revisions. In determinations made in September 2008 and June 2009, the EPA rejected most of the environmental groups' claims, but identified three permit deficiencies which the KDAQ addressed by revising the permit. In August 2009, the EPA issued an Order denying the remaining claims with the exception of two additional deficiencies which the KDAQ was directed to address. The EPA determined that the proposed permit subsequently issued by the KDAQ satisfied the conditions of the EPA Order although the agency recommended certain enhancements to the administrative record. In January 2010, the KDAQ issued a final permit revision incorporating the proposed changes to address the EPA objections. In March 2010, the environmental groups submitted a petition to the EPA to object to the permit revision, which is now pending before the EPA. The Company believes that the final permit as revised should not have a material adverse effect on its financial condition or results of operations. However, until the EPA issues a final ruling on the pending petition and all applicable appeals have been exhausted, the Company cannot predict the final outcome of this matter.

Thermostat Replacement

During January 2010, the Companies announced a voluntary plan to replace certain thermostats, which had been provided to customers as part of the Companies' demand reduction programs, due to concerns that the thermostats may present a safety hazard. Under the plan, the Companies have replaced approximately 90% of the estimated 14,000 thermostats that need to be replaced. Total estimated costs associated with the replacement program are $2 million. However, the Companies cannot fully predict the ultimate outcome of the replacement program or other effects or developments which may be associated with the thermostat replacement matter at this time.

OVEC

KU holds a 2.5% investment interest in OVEC with 10 other electric utilities. KU is not the primary beneficiary; therefore the investment is not consolidated into the Company's financial statements, but is recorded on the cost basis. OVEC is located in Piketon, Ohio, and owns and operates two coal-fired power plants, Kyger Creek Station in Ohio, and Clifty Creek Station in Indiana. KU is contractually entitled to 2.5% of OVEC's output, approximately 55 Mw of generation capacity. Pursuant to the OVEC power purchase contract, the Company may be conditionally responsible for a 2.5% pro-rata share of certain obligations of OVEC under defined circumstances. These contingent liabilities may include unpaid OVEC indebtedness as well as shortfall amounts in certain excess decommissioning costs and post-retirement benefits other than pension. KU's potential proportionate share of OVEC's September 30, 2010 outstanding debt was $35 million.

Environmental Matters

The Company'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. As indicated below and summarized at the conclusion of this section, evolving environmental regulations will likely increase the level of capital and operating and maintenance expenditures incurred by the Company during the next several years. Based on prior regulatory precedent, the Company believes that many costs of complying with such pending or future requirements would likely be recoverable under the ECR or other potential cost-recovery mechanisms, but the Company can provide no assurance as to the ultimate outcome of such proceedings before the regulatory authorities.

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.

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 place in the interim. The remand of the CAIR results in some uncertainty with respect to certain other EPA or state programs and proceedings and the Companies' compliance plans relating thereto due to the interconnection of the CAIR with such associated programs.

In January 2010, the EPA proposed a revised NAAQS for ozone which would increase the stringency of the standard. In addition, the EPA published final revised NAAQS standards for nitrogen dioxide ("NO_2") and SO_2 in February 2010 and June 2010, respectively, which are more stringent than previous standards. Depending on the level of action determined necessary to bring local nonattainment areas into compliance with the revised NAAQS standards, KU's power plants are potentially subject to requirements for additional reductions in SO_2 and NOx emissions.

In July 2010, the EPA issued the proposed CATR, which serves to replace the CAIR. The CATR provides for a two-phase SO_2 reduction program with Phase I reductions due by 2012, and Phase II reductions due by 2014. The CATR provides for NOx reductions in 2012, but the EPA advised that it is studying whether additional NOx reductions should be required for 2014. The CATR is more stringent than the CAIR as it accelerates certain compliance dates and provides for only intrastate and limited interstate trading of emission allowances. In addition to its preferred approach, the EPA is seeking comment on an alternative approach which would provide for individual emission limits at each power plant. The EPA has announced that it will propose additional "transport" rules to address compliance with revised NAAQS standards for ozone and particulate matter which will be issued by the EPA in the future, as discussed below.

Hazardous Air Pollutants. As provided in 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 entered into a consent decree requiring it to promulgate a utility Maximum Achievable Control Technology rule to replace the CAMR with a proposed rule due by March 2011, and a final rule due by November 2011. Depending on the final outcome of the rulemaking, the CAMR could be replaced by new rules with different or more stringent requirements for reduction of mercury and other hazardous air pollutants. Kentucky has also repealed its corresponding state mercury regulations.

Acid Rain Program. 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 Clean Air Act also contains 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 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 the 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 mandated by the NOx SIP Call, KU installed additional NOx controls, including SCR technology, during the 2000 through 2009 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 ECR mechanism. Such monthly recovery is subject to periodic review by the Kentucky Commission.

In order to achieve currently mandated emissions reductions, KU expects to incur additional capital expenditures totaling approximately $285 million during the 2010 through 2012 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.

GHG Developments. 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. As discussed below, 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, 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. The current administration has announced its support for the adoption of mandatory GHG reduction requirements at the federal level. The United States and other countries met in Copenhagen, Denmark in December 2009, in an effort to negotiate a GHG reduction treaty to succeed the Kyoto Protocol, which is set to expire in 2013. In Copenhagen, the U.S. made a nonbinding commitment to, among other things, seek to reduce GHG emissions to 17% below 2005 levels by 2020 and provide financial support to developing countries. The United States and other nations are scheduled to meet in Cancun, Mexico in late 2010 to continue negotiations toward a binding agreement.

GHG Legislation. KU is monitoring on-going efforts to enact GHG reduction requirements and requirements governing carbon sequestration at the state and federal level and is assessing potential impacts of such programs and strategies to mitigate those impacts. In June 2009, the U.S. House of

Representatives passed the American Clean Energy and Security Act of 2009, which is a comprehensive energy bill containing the first-ever nation-wide GHG cap and trade program. The bill would provide for reductions in GHG emissions of 3% below 2005 levels by 2012, 17% by 2020 and 83% by 2050. In order to cushion potential rate impacts for utility customers, approximately 43% of emissions allowances would initially be allocated at no cost to the electric utility sector, with this allocation gradually declining to 7% in 2029 and zero thereafter. The bill would also establish a renewable electricity standard requiring utilities to meet 20% of their electricity demand through renewable energy and energy efficiency by 2020. The bill contains additional provisions regarding carbon capture and sequestration, clean transportation, smart grid advancement, nuclear and advanced technologies and energy efficiency.

In September 2009, the Clean Energy Jobs and American Power Act, which is largely patterned on the House legislation, was introduced in the U.S. Senate. The Senate bill raises the emissions reduction target for 2020 to 20% below 2005 levels and does not include a renewable electricity standard. While the initial bill lacked detailed provisions for the allocation of emissions allowances, a subsequent revision incorporated allowance allocation provisions similar to the House bill. In 2010, Senators Kerry and Lieberman and others have undertaken additional work to draft GHG legislation but have introduced no bill in the Senate to date. In July 2010, Senate Majority Leader Reid announced that he did not anticipate that GHG legislation would be brought to the Senate floor in the current session. The Company is closely monitoring the progress of pending energy legislation, but the prospect for passage of comprehensive GHG legislation in 2010 is uncertain.

GHG Regulations. In April 2007, the U.S. Supreme Court ruled that the EPA has the authority to regulate GHG under the Clean Air Act. In April 2009, the EPA issued a proposed endangerment finding concluding that GHGs endanger public health and welfare, which is an initial rulemaking step under the Clean Air Act. A final endangerment finding was issued in December 2009. In September 2009, the EPA issued a final GHG reporting rule requiring reporting by facilities with annual GHG emissions equivalent to at least 25,000 tons of carbon dioxide. A number of the Company's facilities will be required to submit annual reports commencing with calendar year 2010. In May 2010, the EPA issued a final GHG "tailoring" rule requiring new or modified sources with GHG emissions equivalent to at least 75,000 tons of carbon dioxide to obtain permits under the Prevention of Significant Deterioration Program. Such new or modified facilities would be required to install Best Available Control Technology. While the Company is unaware of any currently available GHG control technology that might be required for installation on new or modified power plants, it is currently assessing the potential impact of the rule. The final rule will apply to new and modified power plants beginning in January 2011. The Company is unable to predict whether mandatory GHG reduction requirements will ultimately be enacted through legislation or regulations.

GHG Litigation. A number of lawsuits have been filed asserting common law claims including nuisance, trespass and negligence against various companies with GHG emitting facilities. In October 2009, a three judge panel of the United States Court of Appeals for the 5th Circuit in the case of Comer v. Murphy Oil reversed a lower court, holding that private plaintiffs have standing to assert certain common law claims against more than 30 utility, oil, coal and chemical companies. In March 2010, the court vacated the opinion of the three-judge panel and granted a motion for rehearing but subsequently denied the appeal due to the lack of a quorum. The appellate ruling leaves in effect the lower court ruling dismissing the plaintiffs' claims. The petitioners filed a petition for a writ of mandamus with the Supreme Court in August 2010. The Comer complaint alleges that GHG emissions from the defendants' facilities contributed to global warming which increased the intensity of Hurricane Katrina. E.ON, the indirect parent of the Companies, was included as a defendant in the complaint but has not been subject to the proceedings due to the failure of the plaintiffs to pursue service under the applicable international procedures. The Companies are currently unable to predict further developments in the Comer case and continue to monitor relevant GHG litigation to identify judicial developments that may be potentially relevant to their operations.

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. The Company is not able to estimate the outcome or potential effects of these matters, including whether substantial fines, penalties or remedial measures may result.

Ghent New Source Review NOV. In March 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 contends that the work in question, as pollution control projects, was exempt from the requirements cited by the EPA. In December 2009, the EPA issued a Section 114 information request seeking additional information on this matter. In March 2010, the Company received an EPA settlement proposal providing for imposition of additional permit limits and emission controls and anticipates continued settlement negotiations with the EPA. Depending on the provisions of a final settlement or the results of litigation, if any, resolution of this matter could involve significant increased operating and capital expenditures. The Company is currently unable to determine the final outcome of this matter or the impact of an unfavorable determination on the Company's financial position or results of operations.

Ash Ponds and Coal-Combustion Byproducts. The EPA has undertaken various initiatives in response to the December 2008 impoundment failure at the Tennessee Valley Authority's Kingston power plant, which resulted in a major release of coal combustion byproducts into the environment. The EPA issued information requests to utilities throughout the country, including KU, to obtain information on their ash ponds and other impoundments. In addition, the EPA inspected a large number of impoundments located at power plants to determine their structural integrity. The inspections included several of KU's impoundments, which the EPA found to be in satisfactory condition. In June 2010, the EPA published proposed regulations for coal combustion byproducts handled in landfills and ash ponds. The EPA has proposed two alternatives: (1) regulation of coal combustion byproducts in landfills and ash ponds as a hazardous waste or (2) regulation of coal combustion byproducts as a solid waste with minimum national standards. Under both alternatives, the EPA has proposed safety requirements to address the structural integrity of ash ponds. In addition, the EPA will consider potential refinements of the provisions for beneficial reuse of coal combustion byproducts.

Water Discharges and PCB Regulations. The EPA has also announced plans to develop revised effluent limitation guidelines governing discharges from power plants and standards for cooling water intake structures. The EPA has further announced plans to develop revised standards governing the use of polychlorinated biphenyls ("PCB") in electrical equipment. The Company is monitoring these ongoing regulatory developments but will be unable to determine the impact until such time as new rules are finalized.

Impact of Pending and Future Environmental Developments. As a company with significant coal-fired generating assets, KU will likely be substantially impacted by pending or future environmental rules or legislation requiring mandatory reductions in GHG emissions or other air emissions, imposing more stringent standards on discharges to waterways, or establishing additional requirements for handling or disposal of coal combustion byproducts. These evolving environmental regulations will likely require an increased level of capital expenditures and increased incremental operating and maintenance costs by the Company over the next several years. Due to the uncertain nature of the final regulations that will ultimately be adopted by the EPA, including the reduction targets and the deadlines that will be applicable, the Company cannot finalize estimates of the potential compliance costs, but should the final rules incorporate additional emission reduction requirements, require more stringent emissions controls or implement more stringent byproducts storage and disposal practices, such costs will likely be significant. With respect to NAAQS, CATR, CAMR replacement and coal combustion byproducts developments, based on a preliminary analysis of proposed regulations, the Company may be required to consider actions such as upgrading existing emissions controls, installing additional emissions controls, upgrading byproducts disposal and storage and possible early replacement of coal-fired units. Capital expenditures for KU associated with such actions are preliminarily estimated to be in the $1.7 billion range over the next 10 years, although final costs may substantially vary. With respect to potential developments in water discharge, revised PCB standards or GHG initiatives, costs in such areas cannot be estimated due to the preliminary status or uncertain outcome of such developments, but would be in addition to the above amount and could be substantial. Ultimately, the precise impact on the Company's operations of these various environmental developments cannot be determined prior to the finalization of such requirements. Based on prior regulatory precedent, the Company believes that many costs of complying with such pending or future requirements would likely be recoverable under the ECR or other potential cost-recovery mechanisms, but the Company can provide no assurance as to the ultimate outcome of such proceedings before the regulatory authorities.

TC2 Water Permit. In May 2010, the Kentucky Waterways Alliance and other environmental groups filed a petition with the Kentucky Energy and Environment Cabinet challenging the Kentucky Pollutant Discharge Elimination System permit issued in April 2010, which covers water discharges from the Trimble County generating station. In October 2010, the hearing officer issued a report and recommended order providing for dismissal of the claims raised by the petitioners. Until such time as the Secretary issues a final order of the agency and all appeals are exhausted, the Company is unable to predict the outcome or precise impact of this matter.

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 a prior Section 114 information request from the EPA relating to new-source issues at KU's Ghent unit 2; completed settlement with state regulators regarding compliance with particulate limits in the air permit for KU's Tyrone generating station; remediation activities for or other risks relating to 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 the GHG emissions from the Company's generating stations. Based on analysis to date, the resolution of these matters is not expected to have a material impact on the Company's operations.

Note 10 – 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 on consolidation of E.ON U.S. Transactions between KU and E.ON subsidiaries are eliminated on consolidation of E.ON. These transactions are generally performed at cost and are in accordance with FERC regulations under the Public Utility Holding Company Act of 2005 and the applicable Kentucky Commission and Virginia Commission regulations. The significant related party transactions are disclosed below.

Intercompany Wholesale Sales and Purchases

KU and LG&E jointly dispatch their generation units with the lowest cost generation used to serve their retail native load. When LG&E has excess generation capacity after serving its own retail native load and its generation cost is lower than that of KU, KU purchases electricity from LG&E. When KU has excess generation capacity after serving its own retail native load and its generation cost is lower than that of LG&E, LG&E purchases electricity from KU. These transactions are recorded as intercompany wholesale sales and purchases are recorded by each company at a price equal to the seller's fuel cost. Savings realized from purchasing electricity intercompany instead of generating from their own higher costs units or purchasing from the market are shared equally between the two Companies. The volume of energy each company has to sell to the other is dependent on its native load needs and its available generation.

These sales and purchases are included in the statements of income as operating revenues, power purchased expenses and other operation and maintenance expenses. KU's intercompany electric revenues and power purchased expense were as follows:

	Three Months Ended September 30,		Nine Months Ended September 30,	
(in millions)	2010	2009	2010	2009
Electric operating revenues from LG&E	$ 3	$ 2	$ 13	$ 18
Power purchased and related operations and maintenance expenses from LG&E	22	22	71	82

Interest Charges

See Note 8, 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 interest expense to affiliated companies was as follows:

	Three Months Ended September 30,		Nine Months Ended September 30,	
(in millions)	2010	2009	2010	2009
Interest on Fidelia loans	$ 18	$ 18	$ 55	$ 51

Interest expense paid to E.ON U.S. on the money pool arrangement was less than $1 million for the three and nine months ended September 30, 2010 and 2009.

Dividends

In September 2010, the Company paid dividends of $50 million to its common shareholder, E.ON U.S.

Capital Contributions

In March and June 2009, the Company received capital contributions of $50 million and $25 million, respectively, from its common shareholder, E.ON U.S.

Other Intercompany Billings

Servco provides the Company with a variety of centralized administrative, management and support services. These services include payroll taxes paid by Servco on behalf of KU, labor and burdens of Servco employees performing services for KU, coal purchases and other vouchers paid by Servco on behalf of KU. The cost of these services is directly charged to the Company, 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, the Companies provide services to each other and to Servco. Billings between the Companies relate to labor and overheads associated with union and hourly employees performing work for the other utility, charges related to jointly-owned generating units and other miscellaneous charges. Billings from KU to Servco include cash received by Servco on behalf of KU, primarily tax settlements, and other payments made by the Company on behalf of other non-regulated businesses which are reimbursed through Servco.

Intercompany billings to and from KU were as follows:

(in millions)	Three Months Ended September 30, 2010	Three Months Ended September 30, 2009	Nine Months Ended September 30, 2010	Nine Months Ended September 30, 2009
Servco billings to KU	$ 64	$ 43	$ 181	$ 121
KU billings to LG&E	-	16	1	63
LG&E billings to KU	28	-	47	-
KU billings to Servco	11	3	11	5

Intercompany Balances

The Company had the following balances with its affiliates:

(in millions)	September 30, 2010	December 31, 2009
Accounts receivable from E.ON U.S.	$ -	$ 9
Accounts payable to LG&E	17	53
Accounts payable to Servco	18	20
Accounts payable to E.ON U.S.	18	-
Accounts payable to Fidelia	18	15
Notes payable to E.ON U.S.	61	45
Long-term debt to Fidelia (including current portion of $33 million)	1,331	1,331

Note 11 – Subsequent Events

Subsequent events have been evaluated through October 29, 2010, the date of issuance of these statements, and these statements contain all necessary adjustments and disclosures resulting from that evaluation.

On October 29, 2010, KU's pollution control bonds were converted from unsecured debt to debt which is collateralized by first mortgage bonds. See Note 1, General, and Note 8, Short-Term and Long-Term Debt.

On October 26, 2010, the FERC issued an Order approving the acquisition of E.ON U.S. by PPL. See Note 1, General.

On October 19, 2010 and October 21, 2010, respectively, the Virginia Commission and Tennessee Regulatory Authority issued Orders approving the acquisition of E.ON U.S. by PPL. On the same dates, KU received Virginia Commission and Tennessee Regulatory Authority approvals to complete certain refinancing transactions in connection with the anticipated PPL acquisition and other business factors. See Note 1, General, and Note 8, Short-Term and Long-Term Debt.

Management's Discussion and Analysis

Overview

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 515,000 customers in 77 counties in central, southeastern and western Kentucky, to approximately 29,000 customers in 5 counties in southwestern Virginia and 5 customers in Tennessee. KU's service area covers approximately 6,600 noncontiguous 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 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. KU's affiliate, LG&E, is a regulated public utility engaged in the generation, transmission, distribution and sale of electric energy and the storage, distribution and sale of natural gas in Kentucky.

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 months ended September 30, 2010, and should be read in connection with the condensed financial statements and notes thereto and the Annual Report for the year ending December 31, 2009. Dollars are in millions unless otherwise noted.

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, 2009.

PPL Acquisition

See Note 1, General, for information regarding the acquisition of E.ON U.S. by PPL, settlement agreements in change of control proceedings, closing conditions and anticipated financing transactions.

Regulatory Matters

See Note 2, Rates and Regulatory Matters, for information regarding rate cases, regulatory assets and liabilities and other regulatory matters.

Environmental Matters

General

Protection of the environment is a major priority for KU and a significant element of its business activities. KU's properties and operations are subject to extensive environmental-related oversight by federal, state and local regulatory agencies, including via air quality, water quality, waste management and similar laws and regulations. Therefore, KU must conduct its operations in accordance with numerous permit and other requirements issued under or contained in such laws or regulations.

Climate Change

Recent developments continue to indicate an increased possibility of significant climate change or GHG legislation or regulation, at the international, federal, regional and state levels. During December 2009, as part of the United Nation's Copenhagen Accord, the United States agreed to a non-binding goal to reduce GHG emissions to 17% below 2005 levels by 2020. Additionally, during 2009, the U.S. House of Representatives passed comprehensive GHG legislation, which included a number of measures to limit GHG emissions and achieve GHG emission reduction targets below 2005 levels of 3% by 2012, 17% by 2020 and 83% by 2050. Similar legislation has been considered in the U.S. Senate, but the prospects for passage remain uncertain. In late 2009, the EPA issued or proposed various regulatory initiatives relating to GHG matters, including an endangerment finding relating to mobile sources of GHGs, a GHG reporting requirement and a rule relating to permitting requirements for new or modified GHG emission sources. Finally, a number of U.S. states, although not currently including Kentucky, have adopted GHG-reduction legislation or regulation of various sorts. The developing GHG initiatives include a number of differing structures and formats, including direct limitations on GHG sources, issuance of allowances for GHG emissions, cap-and-trade programs for such allowances, renewable or alternative generation portfolio standards and mechanisms relating to demand reduction, energy efficiency, smart-grid, transmission expansion, carbon-sequestration or other GHG-reducing efforts. While the final terms and impacts of such initiatives cannot be estimated, KU, as a primarily coal-fired utility, could be highly affected by such proceedings.

Other Environmental Regulatory Initiatives

Additionally, the EPA has proposed or announced that it intends to propose a number of additional environmental regulations that could substantially impact utilities with coal-fired generating assets. These regulatory initiatives include revisions to the ambient air quality standards for SO_2, NO_2, ozone, and particulate matter 2.5 microns in size or less, rules aimed at mitigating the interstate transport of SO_2 and NOx, a program governing emissions of hazardous air pollutants from utility generating units, a program for the management of coal combustion residuals, revised effluent guidelines for utility generating facilities and standards for water intake structures. Such requirements could potentially mandate upgrade of existing emission controls, installation of additional emission controls such as FGDs, SCRs, fabric filter bag houses, activated carbon injection, wet electrostatic precipitators, closure of ash ponds and retrofit of landfills, installation of cooling towers, deployment of new water treatment technologies and retirement of facilities that cannot be retrofitted on a cost effective basis.

The cost to KU and the effect on KU's business of complying with potential GHG restrictions and other environmental regulatory initiatives will depend on the details of the programs ultimately enacted. Some of the design elements which may have the greatest effect on KU include (a) the required levels and timing of emissions caps, discharge limits or similar standards (b) the sources covered by such requirements, (c) transition and mitigation provisions, such as phase-in periods, free allowances or price caps, (d) the availability and pricing of relevant mitigation or control technologies, goods or services and (e) economic, market and customer reaction to electricity price and demand changes due to environmental concerns.

Ultimately, environmental matters or potential environmental matters can represent an important element of current or future potential capital requirements, future unit retirement or replacement decisions, supply and demand for electricity, operating and maintenance expenses or compliance risks for the Company. Base on prior regulatory precedent, KU currently anticipates that many of such direct costs may be recoverable through rates or other regulatory mechanisms, particularly with respect to coal-related generation, but the availability, timing or completeness of such rate recovery cannot be assured. Ultimately, climate change and other environmental matters will likely increase the level of capital expenditures and operating and maintenance costs incurred by the Company during the next several years. With respect to NAAQS, CATR, CAMR replacement and coal combustion byproducts developments, based on a preliminary analysis of proposed regulations, the Company may be required to consider actions such as upgrading existing emissions controls, installing additional emissions controls, upgrading byproducts disposal and storage and possible early replacement of coal-fired units. Capital expenditures for KU associated with such actions are preliminarily estimated to be in the $1.7 billion range over the next 10 years, although final costs may substantially vary. See Management's Discussion and Analysis and Note 9, Commitments and Contingencies, for additional 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, 2010, Compared to
Three Months Ended September 30, 2009

Net Income

Net income was $54 million for the three months ended September 30, 2010, compared to $66 million for the same period in 2009. The decrease was primarily the result of the following:

	Three Months Ended September 30, 2010	Three Months Ended September 30, 2009	Increase (Decrease)
Total operating revenues	$ 416	$ 341	$ 75
Total operating expenses	311	216	95
Operating income	105	125	(20)
Interest expense to affiliated companies	18	18	-
Other income (expense) – net	(1)	(2)	1
Income before income taxes	86	105	(19)
Income tax expense	32	39	(7)
Net income	$ 54	$ 66	$ (12)

Operating Revenues

The $75 million increase in operating revenues in the three months ended September 30, 2010, was primarily due to:

	Increase (Decrease)
Retail sales volumes (a)	$ 40
Retail base rates (b)	14
ECR surcharge due to increased recoverable capital spending	10
Retail FAC costs billed to customers due to higher fuel prices	6
Other	5
	$ 75

(a) Primarily due to increased consumption by residential customers as a result of increased cooling degree days and higher energy usage by industrial customers as a result of improved economic conditions and increased cooling degree days.

(b) Primarily due to higher rates effective August 1, 2010. See Note 2, Rates and Regulatory Matters, for further discussion of the 2010 Kentucky rate case.

Operating 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. Operating expenses follow:

	Three Months Ended September 30, 2010	Three Months Ended September 30, 2009	Increase (Decrease)
Fuel for electric generation	$ 146	$ 114	$ 32
Power purchased	41	47	(6)
Other operation and maintenance expenses	86	22	64
Depreciation, accretion and amortization	38	33	5
Total operating expenses	$ 311	$ 216	$ 95

Fuel for Electric Generation

The $32 million increase in fuel for electric generation in the three months ended September 30, 2010, was primarily due to increased volumes of fuel usage due to increased retail sales volumes.

Power Purchased

The $6 million decrease in power purchased expense in the three months ended September 30, 2010, was primarily due to:

	Increase (Decrease)
Third-party purchased volumes for native load	$ (8)
Demand payments for third-party purchase	(4)
Prices for purchases used to serve retail customers	6
	$ (6)

Other Operation and Maintenance Expenses

Other operation and maintenance expenses increased $64 million in the three months ended September 30, 2010, due to $55 million of increased maintenance expenses, and $9 million of increased other operation expenses. These increases were primarily due to distribution expenses ($53 million related to maintenance and $4 million related to other operations) incurred in the first quarter of 2009 for wind and ice storm restoration that were reclassified to a regulatory asset in the third quarter of 2009.

Income Tax Expense

See Note 7, Income Taxes, for a reconciliation of differences between the U.S. federal income tax expense at statutory rates and KU's income tax expense.

Nine Months Ended September 30, 2010, Compared to
Nine Months Ended September 30, 2009

Net Income

Net income was $129 million for the nine months ended September 30, 2010, compared to $99 million for the same period in 2009. The increase was primarily the result of the following:

	Nine Months Ended September 30, 2010	Nine Months Ended September 30, 2009	Increase (Decrease)
Total operating revenues	$ 1,146	$ 1,009	$ 137
Total operating expenses	883	812	71
Operating income	263	197	66
Interest expense to affiliated companies	55	51	4
Other income (expense) – net	(3)	2	(5)
Income before income taxes	205	148	57
Income tax expense	76	49	27
Net income	$ 129	$ 99	$ 30

Operating Revenues

The $137 million increase in operating revenues in the nine months ended September 30, 2010, was primarily due to:

	Increase (Decrease)
Retail sales volumes (a)	$ 98
Retail base rates (b)	14
ECR surcharge due to increased recoverable capital spending	10
Miscellaneous operating revenue (c)	8
DSM revenue due to increased recoverable program spending	6
Other	1
	$ 137

(a) Primarily due to increased consumption by residential customers as a result of increased cooling and heating degree days and higher energy usage by industrial customers as a result of improved economic conditions and increased cooling and heating degree days.
(b) Primarily due to higher rates effective August 1, 2010. See Note 2, Rates and Regulatory Matters, for further discussion of the 2010 Kentucky rate case.
(c) Primarily related to increased late payment charges and transmission service revenues.

Operating 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. Operating expenses follow:

	Nine Months Ended September 30, 2010	Nine Months Ended September 30, 2009	Increase (Decrease)
Fuel for electric generation	$ 391	$ 329	$ 62
Power purchased	135	154	(19)
Other operation and maintenance expenses	251	230	21
Depreciation, accretion and amortization	106	99	7
Total operating expenses	$ 883	$ 812	$ 71

Fuel for Electric Generation

The $62 million increase in fuel for electric generation in the nine months ended September 30, 2010, was primarily due to:

	Increase (Decrease)
Fuel usage volumes due to increased native load and wholesale sales	$ 73
Commodity and transportation costs for coal	(11)
	$ 62

Power Purchased

The $19 million decrease in power purchased expense in the nine months ended September 30, 2010, was primarily due to:

	Increase (Decrease)
Third-party purchased volumes for native load	$ (16)
Purchases from LG&E due to volume (a)	(13)
Demand payments for third-party purchases	(5)
Prices for purchases used to serve retail customers	7
OMU settlement received in 2009 (b)	6
Purchases from LG&E due to fuel costs	2
	$ (19)

(a) Primarily due to increased consumption by residential customers at LG&E as a result of increased cooling and heating degree days and increased coal-fired generation outages in the first six months of 2010 and higher energy usage by industrial customers as a result of improved economic conditions and increased cooling and heating degree days. See Note 10, Related Party Transactions, for further discussion of the mutual agreement for wholesale sales and purchases between the Companies.

(b) See Note 9, Commitments and Contingencies, for further discussion of the OMU settlement.

Other Operation and Maintenance Expenses

Other operation and maintenance expenses increased $21 million in the nine months ended September 30, 2010, due to $19 million of increased other operation expenses and $2 million of increased maintenance expenses.

Other Operation Expenses

The $19 million increase in other operation expenses in the nine months ended September 30, 2010, was primarily due to:

	Increase (Decrease)
Transmission expense (a)	$ 7
Administrative and general (b)	6
Steam expense due to increased generation in 2010	5
Other	1
	$ 19

(a) Primarily due to transmission expense for a third party pursuant to a settlement agreement, the establishment of a regulatory asset approved by the Kentucky Commission for the EKPC settlement in 2009, net of nine months of amortization expense recorded in 2010, and increased transmission expense due to transmission charges for FERC jurisdictional municipal customers now unbundled from energy.

(b) Primarily due to increased bad debt expense due to higher billed revenues, implementation of a late payment charge and a higher net charge-off percentage, increased labor costs, and increased insurance cost.

Interest Expense to Affiliated Companies

The $4 million increase in interest expense to affiliated companies in the nine months ended September 30, 2010, was primarily due to increased intercompany notes outstanding.

Income Tax Expense

See Note 7, Income Taxes, for a reconciliation of differences between the U.S. federal income tax expense at statutory rates and KU's income tax expense.

Financial Condition

Liquidity and Capital Resources

	September 30, 2010	December 31, 2009
Cash and cash equivalents	$ 2	$ 2
Current portion of long-term debt	228	228
Current portion of long-term debt to affiliated company	33	33
Notes payable to affiliated company	61	45

Activity in KU's cash and cash equivalents in the nine months ended September 30, 2010, included the following:

	Increase (Decrease)
Cash provided by operating activities	$ 300
Construction expenditures	(218)
A net increase in short-term borrowings from affiliated company	16
Expenditures to purchase assets from affiliate	(48)
Payment of dividends	(50)
	$ -

Working Capital Deficiency

As of September 30, 2010, KU had a working capital deficiency of $205 million, primarily due to the terms of certain tax-exempt bonds totaling $228 million, which allow the investors to put the bonds back to the Company causing them to be classified as current portion of long-term bonds. The Company has adequate liquidity facilities to repurchase any bonds put back to the Company. Working capital deficiencies can be funded through an intercompany money pool agreement through bilateral lines of credit or drawings under letters of credit. See Note 8, Short-Term and Long-Term Debt. KU believes that its sources of funds will be sufficient to meet the needs of its business in the foreseeable future.

Auction Rate Securities

Auctions for auction rate securities issued by KU continued to fail during the quarter. KU did not hold any of its own auction rate securities at September 30, 2010 and December 31, 2009. See Note 8, Short-Term and Long-Term Debt, for further discussion of auction rate securities.

Debt

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 2009, 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 2011, allowing short-term borrowing of up to $400 million. These short-term funds are made available via the Company's participation 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.

See Note 1, General, for information on PPL related financing and Note 8, Short-Term and Long-Term Debt, for information on redemptions, maturities and issuances of long-term debt.

Common Stock Dividends

In September 2010, the Company paid dividends of $50 million to its common shareholder, E.ON U.S. KU uses net cash generated from its operations and external financing (including financing from affiliates) to fund the payment of dividends. Future dividends, declared at the discretion of the Board of Directors, will be dependent on future earnings, financial requirements and other factors.

Credit Ratings

KU's credit ratings reflect the views of two national rating agencies. 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. In October 2010, one national rating agency revised downward the short-term credit rating of the pollution control bonds and the Company's issuer rating as a result of the pending acquisition by PPL. See Note 8, Short-Term and Long-Term Debt, for a discussion of downgrade actions related to the pollution control bonds caused by a change in the rating of the entity insuring those bonds.

KU has various derivative and non-derivative contracts, including contracts for the sale and purchase of electricity and fuel, which contain provisions requiring KU to post additional collateral or permit the counterparty to terminate the contract if KU's credit rating were to fall below investment grade. At September 30, 2010, KU had no open positions under these contracts that would require the Company to post collateral to counterparties if KU's credit rating had been downgraded below investment grade for both derivative and non-derivative commodity and commodity-related contracts used in its generation, marketing and trading operations.

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, 2012, to total approximately $1.1 billion, consisting primarily of the following:

Construction of generation assets	$	305
Construction of distribution assets		245
Ash pond and landfill projects		210
Brown SCR		155
Installation of FGDs on Ghent and Brown units		125
Information technology projects		35
Other projects		25
Construction of TC2 (includes $5 million for environmental controls)		25
	$	1,125

In addition to the amounts in the table shown above, evolving environmental regulations will likely increase the level of capital expenditures above the amounts currently expected over the next several years. With respect to NAAQS, CATR, CAMR replacement and coal combustion byproducts developments, based on a preliminary analysis of proposed regulations, the Company may be required to consider actions such as upgrading existing emissions controls, installing additional emissions controls, upgrading byproducts disposal and storage and possible early replacement of coal-fired units. Capital expenditures for KU associated with such actions are preliminarily estimated to be in the $1.7 billion range over the next 10 years, although final costs may substantially vary. See Note 9, Commitments and Contingencies, for further discussion of environmental matters. 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. Credit market conditions can affect aspects of the availability, terms or methods in KU and LG&E fund their capital requirements. KU and LG&E anticipate funding future capital requirements through operating cash flow, debt and/or infusions of capital from their parent.

Controls and Procedures

Management 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 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 condensed 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.

As of December 31, 2009, 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, management has assessed the effectiveness of the Company's internal control over financial reporting as of December 31, 2009, using the criteria set forth by the Committee of Sponsoring Organizations of the Treadway Commission in *Internal Control – Integrated Framework.* Management has concluded that, as of December 31, 2009, the Company's internal control over financial reporting was effective based on those criteria. There have been no changes in the Company's internal control over financial reporting that occurred during the nine months ended September 30, 2010, that has materially affected or is reasonably likely to materially affect the Company's internal control over financial reporting.

The effectiveness of the Company's internal control over financial reporting as of December 31, 2009, was audited by PricewaterhouseCoopers LLP, an independent accounting firm, as stated in its report which is included in the 2009 KU Annual Report.

Legal Proceedings

For a description of the significant legal proceedings, including, but not limited to, certain rates and regulatory, environmental, climate change and litigation matters, involving KU, reference is made to the information under the following captions of the Company's Annual Report for the year ended December 31, 2009: 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 Note 2, Rates and Regulatory Matters; Note 9, Commitments and Contingencies; and Note 11, Subsequent Events, of this quarterly report. Except as described in this quarterly report, to date, the proceedings reported in the Company's Annual Report for the year ended December 31, 2009, 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, the Company 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 the Company's financial position or results of operations.

KENTUCKY UTILITIES COMPANY
FINANCIAL STATEMENTS

DECEMBER 31, 2010

Kentucky Utilities Company

Financial Statements and Additional Information

As of December 31, 2010 and 2009 and

for the years ended December 31, 2010, 2009 and 2008

Index of Abbreviations

AG	Attorney General of Kentucky
ARO	Asset Retirement Obligation
ASC	Accounting Standards Codification
BART	Best Available Retrofit Technology
CAIR	Clean Air Interstate Rule
CAMR	Clean Air Mercury Rule
CATR	Clean Air Transport 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
CT	Combustion Turbine
DSM	Demand Side Management
ECR	Environmental Cost Recovery
EEI	Electric Energy, Inc.
EKPC	East Kentucky Power Cooperative, Inc.
E.ON	E.ON AG
E.ON U.S.	E.ON U.S. LLC and Subsidiaries
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)
GAAP	U.S. Generally Accepted Accounting Principles
GAC	Group Annuity Contract
GHG	Greenhouse Gas
Gwh	Gigawatt hours or one thousand Mwh
IBEW	International Brotherhood of Electrical Workers
IMEA	Illinois Municipal Electric Agency
IMPA	Indiana Municipal Power Agency
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
LIBOR	London Interbank Offered Rate
LKE	LG&E and KU Energy LLC and Subsidiaries (formerly E.ON U.S. LLC and Subsidiaries)
MISO	Midwest Independent Transmission System Operator, Inc.
MMBtu	Million British thermal units

Index of Abbreviations

Moody's	Moody's Investor Services, Inc.
MVA	Megavolt-ampere
Mw	Megawatts
Mwh	Megawatt hours
NAAQS	National Ambient Air Quality Standards
NERC	North American Electric Reliability Corporation
NO_2	Nitrogen Dioxide
NOV	Notice of Violation
NOx	Nitrogen Oxide
OATT	Open Access Transmission Tariff
OMU	Owensboro Municipal Utilities
OVEC	Ohio Valley Electric Corporation
PPL	PPL Corporation
Predecessor	The Company during the time period prior to November 1, 2010
PUHCA 2005	Public Utility Holding Company Act of 2005
RSG	Revenue Sufficiency Guarantee
S&P	Standard & Poor's Rating Service
SCR	Selective Catalytic Reduction
SERC	SERC Reliability Corporation
Servco	LG&E and KU Services Company (formerly E.ON U.S. Services Inc.)
SIP	State Implementation Plan
SO_2	Sulfur Dioxide
SPP	Southwest Power Pool, Inc
Successor	The Company during the time period after October 31, 2010
TC1	Trimble County Unit 1
TC2	Trimble County Unit 2
TVA	Tennessee Valley Authority
Utilities	KU and LG&E
VDT	Value Delivery Team Process
Virginia Commission	Virginia State Corporation Commission

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Forward-Looking Information

KU uses forward-looking statements in this annual report. Statements that are not historical facts are forward-looking statements, and are based on beliefs and assumptions of management, and on information currently available to management. Forward-looking statements include statements preceded by, followed by or using such words as "believe," "expect," "anticipate," "plan," "estimate" or similar expressions. Such statements speak only as of the date they are made, and the Company undertakes no obligation to update publicly any of them in light of new information or future events. Actual results may materially differ from those implied by forward-looking statements due to known and unknown risks and uncertainties. Factors that could cause actual results to differ materially from those indicated in any forward-looking statement include, but are not limited to:

- fuel supply availability;
- weather conditions affecting generation production, customer energy use and operating costs;
- operation, availability and operating costs of existing generation facilities;
- transmission and distribution system conditions and operating costs;
- collective labor bargaining negotiations;
- the outcome of litigation against the Company;
- potential effects of threatened or actual terrorism or war or other hostilities;
- commitments and liabilities;
- market demand and prices for energy, capacity, transmission services, emission allowances and delivered fuel;
- competition in retail and wholesale power markets;
- liquidity of wholesale power markets;
- defaults by counterparties under the Company's energy, fuel or other power product contracts;
- market prices of commodity inputs for ongoing capital expenditures;
- capital market conditions, including the availability of capital or credit, changes in interest rates, and decisions regarding capital structure;
- the fair value of debt and equity securities and the impact on defined benefit costs and resultant cash funding requirements for defined benefit plans;
- interest rates and their effect on pension and retiree medical liabilities;
- volatility in or the impact of other changes in financial or commodity markets and economic conditions;
- profitability and liquidity, including access to capital markets and credit facilities;
- new accounting requirements or new interpretations or applications of existing requirements;
- securities and credit ratings;
- current and future environmental conditions and requirements and the related costs of compliance, including environmental capital expenditures, emission allowance costs and other expenses;
- political, regulatory or economic conditions in states, regions or countries where the Company conducts business;
- receipt of necessary governmental permits, approvals and rate relief;
- new state or federal legislation, including new tax, environmental, health care or pension-related legislation;
- state or federal regulatory developments;
- the impact of any state or federal investigations applicable to the Company and the energy industry;
- the effect of any business or industry restructuring;
- development of new projects, markets and technologies;

- performance of new ventures; and
- asset acquisitions and dispositions.

In light of these risks and uncertainties, the events described in the forward-looking statements might not occur or might occur to a different extent or at a different time than the Company has described. For additional details regarding these and other risks and uncertainties, see Risk Factors.

Business

General

KU, incorporated in Kentucky in 1912 and in Virginia in 1991, is a regulated utility engaged in the generation, transmission, distribution and sale of electric energy in Kentucky, Virginia and Tennessee. KU provides electric service to approximately 514,000 customers in 77 counties in central, southeastern and western Kentucky, to approximately 30,000 customers in five counties in southwestern Virginia and less than ten customers in Tennessee. KU's service area covers approximately 6,600 noncontiguous square miles. Approximately 98% of the electricity generated by KU is produced by its coal-fired electric generating stations. The remainder is generated by natural gas and oil fueled CTs and a hydroelectric power plant. In Virginia, KU operates under the name Old Dominion Power Company. KU also sells wholesale electric energy to 12 municipalities.

On November 1, 2010, KU became an indirect wholly owned subsidiary of PPL, when PPL acquired all of the outstanding limited liability company interests in the Company's direct parent, LKE, from E.ON US Investments Corp. LKE, a Kentucky limited liability company, also owns the affiliate, LG&E, a regulated utility engaged in the generation, transmission, distribution and sale of electric energy and distribution and sale of natural gas in Kentucky. Following the acquisition, the Company's business has not changed. KU and LG&E are continuing as subsidiaries of LKE, which is now an intermediary holding company in the PPL group of companies.

Headquartered in Allentown, Pennsylvania, PPL is an energy and utility holding company that was incorporated in 1994. Through its subsidiaries, PPL owns or controls about 19,000 megawatts of generating capacity in the U.S., sells energy in key U.S. markets and delivers electricity and natural gas to about 5.3 million customers in the U.S. and the U.K.

Predecessor and Successor

KU's historical financial results are presented using "Predecessor" or "Successor" to designate the periods before or after PPL's acquisition of LKE. Predecessor covers the time period prior to November 1, 2010. Successor covers the time period after October 31, 2010. Certain accounting and presentation methods were changed to acceptable alternatives to conform to PPL accounting policies and the cost basis of certain assets and liabilities were changed as of November 1, 2010, as a result of the application of push-down accounting. Consequently, the financial position, results of operations and cash flows for the Successor period are not comparable to the Predecessor period.

Despite the separate presentation, the core operations of the Company have not changed. See Note 1, Summary of Significant Accounting Policies, for the major differences in Predecessor and Successor accounting policies. See Note 2, Acquisition by PPL, for information regarding the acquisition and the purchase accounting adjustments.

Operations

Dollars are in millions unless otherwise noted.

The sources of operating revenues and volumes of sales for the following periods in 2010, 2009 and 2008 were as follows:

	Successor		Predecessor					
	November 1, 2010 through December 31, 2010		January 1, 2010 through October 31, 2010		Year Ended December 31, 2009		Year Ended December 31, 2008	
	Revenues	Volumes (Gwh)	Revenues	Volumes (Gwh)	Revenues	Volumes (Gwh)	Revenues	Volumes (Gwh)
Residential	$ 106	1,394	$ 440	5,788	$ 480	6,594	$ 462	6,803
Industrial and commercial	117	1,876	588	9,152	637	10,171	636	10,709
Municipals	15	326	88	1,676	91	1,848	92	1,971
Other retail	20	273	114	1,453	118	1,647	108	1,707
Wholesale	5	68	18	376	29	660	107	2,894
	$ 263	3,937	$ 1,248	18,445	$ 1,355	20,920	$ 1,405	24,084

KU's peak load in 2010 was 4,517 Mw on December 15, 2010, when the temperature dropped to a low of 3 degrees Fahrenheit in Lexington. KU's all time peak load was 4,640 Mw and occurred on January 16, 2009, when the temperature dropped to a low of -2 degrees Fahrenheit in Lexington.

The Company's power generating system includes coal-fired steam generating stations, with natural gas and oil fueled CTs which supplement the system during peak or emergency periods. As of December 31, 2010, KU's system capacity was:

Fuel/Plant	Total Summer Mw Capacity (a)	% Ownership	Ownership or Lease Interest in Mw	Location
Coal (steam)				
Ghent	1,918	100.00	1,918	Carroll County, KY
E.W. Brown	684	100.00	684	Mercer County, KY
Green River	163	100.00	163	Muhlenberg County, KY
Tyrone	71	100.00	71	Woodford County, KY
OVEC - Clifty Creek (b)	1,304	2.50	33	Jefferson County, IN
OVEC - Kyger Creek (b)	1,086	2.50	27	Gallia County, OH
Total steam	5,226		2,896	
Natural gas/oil (combustion turbines)				
E.W. Brown Units 8-11	480	100.00	480	Mercer County, KY
Trimble County Units 7-10 (c)	640	63.00	403	Trimble County, KY
Trimble County Units 5-6 (c)	320	71.00	227	Trimble County, KY
E.W. Brown Units 6-7 (c)	338	62.00	214	Mercer County, KY
Paddy's Run (c)	158	47.00	74	Jefferson County, KY
E.W. Brown Unit 5	129	47.00	63	Mercer County, KY
Haefling	36	100.00	36	Fayette County, KY
Total combustion turbines	2,101		1,497	

Fuel/Plant	Total Summer Mw Capacity (a)	% Ownership	Ownership or Lease Interest in Mw	Location
Hydro				
Dix Dam Hydroelectric Station	24	100.00	24	Mercer County, KY
Total hydro	24		24	
Total system capacity	7,351		4,417	

(a) The capacity of generation units is based on a number of factors, including the operating experience and physical conditions of the units and may be revised periodically to reflect changed circumstances.
(b) KU is contractually entitled to 2.50% of OVEC's output based on a power purchase agreement which is comprised of annual minimum debt service payments, as well as contractually-required reimbursement of plant operating, maintenance and other expenses. OVEC's capacity is shown at unit nameplate ratings.
(c) Units are jointly owned with LG&E. See Note 14, Jointly Owned Electric Utility Plant, for further information.

With limited exceptions the Company took care, custody and control of TC2 on January 22, 2011, and has dispatched the unit to meet customer demand since that date. KU and the contractor agreed to a further amendment of the construction agreement whereby the contractor will complete certain actions relating to identifying and completing any necessary modifications to allow operation of TC2 on all fuels in accordance with initial specifications prior to certain dates, and amending the provisions relating to liquidated damages. Unit 2 is coal-fired and has a capacity of 760 Mw, of which KU's share is 462 Mw.

On December 31, 2010, KU's transmission system included 132 substations (54 of which are shared with the distribution system) with transformer capacity of approximately 13,136 MVA and approximately 4,076 miles of lines. The distribution system included 480 substations (54 of which are shared with the transmission system) with transformer capacity of approximately 7,044 MVA, and approximately 14,123 miles of overhead lines and 2,221 miles of underground conduit.

KU had a power supply contract with OMU that was terminated by OMU in May 2010. KU owns 20% of EEI's common stock and 2.5% of OVEC's common stock. KU has power purchase rights for its portion of OVEC's output. Additional information regarding this relationship is provided in Note 1, Summary of Significant Accounting Policies and Note 13, Commitments and Contingencies.

KU contracts with the TVA to act as KU's transmission reliability coordinator and SPP to function as KU's independent transmission operator, pursuant to FERC requirements. The TVA and SPP contracts provide services through August 31, 2011 and August 31, 2012, respectively. See Note 3, Rates and Regulatory Matters, for further information.

KU and LG&E jointly dispatch their generation units with the lowest cost generation used to serve their retail native load. When LG&E has excess generation capacity after serving its own retail native load and its generation cost is lower than that of KU, KU purchases electricity from LG&E. When KU has excess generation capacity after serving its own retail native load and its generation cost is lower than that of LG&E, LG&E purchases electricity from KU. These transactions are recorded as intercompany wholesale sales and purchases and are recorded by each company at a price equal to the seller's fuel cost. Savings realized from purchasing electricity intercompany instead of generating from their own higher costs units or purchasing from the market are shared equally between the Utilities. The volume of energy each company has to sell to the other is dependent on its native load needs and its available generation.

Substantially all of KU's real and tangible property located in Kentucky is subject to a mortgage lien, securing its first mortgage bonds. See Note 11, Long-Term Debt, for further information.

Rates and Regulations

PPL, KU's ultimate parent, is a holding company under PUHCA 2005. PPL, 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.

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

On April 28, 2010, E.ON U.S. announced that a Purchase and Sale Agreement (the "Agreement") had been entered into among E.ON US Investments Corp., PPL and E.ON.

The transaction was subject to customary closing conditions, including the expiration or termination of the applicable waiting period under the Hart-Scott-Rodino Act, receipt of required regulatory approvals (including the FERC and state regulators in Kentucky, Virginia and Tennessee) and the absence of injunctions or restraints imposed by governmental entities.

Change of control and financing-related applications were filed on May 28, 2010, with the Kentucky Commission and on June 15, 2010, with the Virginia Commission and the Tennessee Regulatory Authority. An application with the FERC was filed on June 28, 2010. During the second quarter of 2010, a number of parties were granted intervenor status in the Kentucky Commission proceedings and data request filings and responses occurred. Early termination of the Hart-Scott-Rodino waiting period was received on August 2, 2010.

A hearing in the Kentucky Commission proceedings was held on September 8, 2010, at which time a unanimous settlement agreement was presented. In the settlement, KU committed that no base rate increases would take effect before January 1, 2013. The KU rate increases that took effect on August 1, 2010, were not impacted by the settlement. Under the terms of the settlement, KU retains the right to seek approval for the deferral of "extraordinary and uncontrollable costs." Interim rate adjustments will continue to be permissible during that period for existing fuel, environmental and demand-side management cost trackers. The agreement also substitutes an acquisition savings shared deferral mechanism for the requirement that the Company file a synergies plan with the Kentucky Commission. This mechanism, which will be in place until the earlier of five years or the first day of the year in which a base rate increase becomes effective, permits KU to earn up to a 10.75% return on equity. Any earnings above a 10.75% return on equity will be shared with customers on a 50%/50% basis. On September 30, 2010, the Kentucky Commission issued an Order approving the transfer of ownership of KU via the acquisition of E.ON U.S. by PPL, incorporating the terms of the submitted settlement. On October 19, 2010 and October 21, 2010, respectively, Orders approving the acquisition of E.ON U.S. by PPL were received from the Virginia Commission and the Tennessee Regulatory Authority. The Commissions' Orders contained a number of other commitments with regard to operations, workforce, community involvement and other matters.

In mid-September 2010, KU and other applicants in the FERC change of control proceeding reached an agreement with the protesters, whereby such protests have been withdrawn. The agreement, which was filed for consideration with the FERC, includes various conditional commitments, such as a continuation of certain existing undertakings with protesters in prior cases, an agreement not to terminate certain KU municipal customer contracts prior to January 2017, an exclusion of any transaction-related costs from wholesale energy and tariff customer rates to the extent that KU agreed not to seek the same transaction-related cost from retail customers and agreements to coordinate with protesters in certain open or ongoing matters. A FERC Order approving the transaction was received on October 26, 2010, and the transaction was completed on November 1, 2010.

In January 2010, KU filed an application with the Kentucky Commission requesting an increase in electric base rates of approximately 12%, or $135 million annually. In June 2010, KU and all of the intervenors, except the AG, agreed to a stipulation providing for an increase in electric base rates of $98 million annually and filed a request with the Kentucky Commission to approve such settlement. An Order in the proceeding was issued in July 2010, approving all the provisions in the stipulation, including a return on equity range of 9.75-10.75%. The new rates became effective on August 1, 2010.

In June 2009, KU filed an application with the Virginia Commission requesting an increase in electric base rates for its Virginia jurisdictional customers in an amount of $12 million annually or approximately 21%. The proposed increase reflected a proposed rate of return on rate base of 8.586% based on a return on equity of 12%. As permitted, pursuant to a Virginia Commission Order, KU elected to implement the proposed rates effective November 1, 2009, on an interim basis. During December 2009, KU and the Virginia Commission Staff agreed to a Stipulation and Recommendation authorizing a base rate revenue increase of $11 million annually and a return on rate base of 7.846% based on a 10.5% return on common equity. In March 2010, the Virginia Commission issued an Order approving the stipulation, with the increased rates to be put into effect as of April 1, 2010. As part of the stipulation, KU refunded approximately $1 million in interim rate amounts in excess of the ultimate approved rates.

In January 2009, a significant ice storm passed through KU's service area causing approximately 199,000 customer outages, followed closely by a severe wind storm in February 2009 causing approximately 44,000 customer outages. The Company filed an application with the Kentucky Commission in April 2009, requesting approval to establish a regulatory asset and defer for future recovery approximately $62 million in incremental operation and maintenance expenses related to the storm restoration. In September 2009, the Kentucky Commission issued an Order allowing the Company to establish a regulatory asset of up to $62 million based on its actual costs for storm damages and service restoration due to the January and February 2009 storms. In September 2009, the Company established a regulatory asset of $57 million for actual costs incurred. KU received approval in its 2010 base rate case to recover this asset over a ten year period with recovery beginning August 1, 2010.

In September 2008, high winds from the remnants of Hurricane Ike passed through the service area 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. In December 2008, the Company established a regulatory asset of $2 million for actual costs incurred. The Company received approval in its 2010 base rate case to recover this asset over a ten year period beginning August 1, 2010.

In September 2008, KU filed an application with the FERC for increases in electric base rates applicable to wholesale power sales contracts or interchange agreements involving, collectively, twelve Kentucky municipalities. The application requested a shift from an all-in stated unit charge rates to an unbundled formula rate, including an annual adjustment mechanism. In May 2009, the FERC issued an Order approving a settlement among the parties in the case, incorporating increases of approximately 3% from prior rates and a return on equity of 11%. In May 2010, KU submitted to the FERC the proposed current annual adjustments to the formula rates, which incorporated certain proposed increases. Updated rates, including certain further adjustments from a review process involving wholesale requirements customers, became effective as of July 1, 2010.

By mutual agreement, the parties' settlement of the 2008 application left outstanding the issue of whether KU must allocate to the municipal customers a portion of renewable resources it may be required to procure on behalf of its retail ratepayers. An Order was issued by the FERC in July 2010, indicating that KU is not required to allocate a portion of any renewable resources to the twelve municipalities, thus resolving the remaining issue.

In July 2008, KU filed an application with the Kentucky Commission requesting an increase in electric base rates. In January 2009, KU, the AG, the KIUC and all other parties to the rate case filed a settlement agreement with the Kentucky Commission, under which KU's electric base rates decreased by $9 million annually. An Order approving the settlement agreement was received in February 2009. The new rates were implemented effective February 6, 2009.

For a further discussion of regulatory matters, see Note 3, Rates and Regulatory Matters.

Coal Supply

Coal-fired generating units provided approximately 98% of KU's net kWh generation for 2010. The remaining net generation was provided by natural gas and oil fueled CTs 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. The Company has no nuclear generating units and has no plans to build any in the foreseeable future.

Fuel inventory is maintained at levels estimated to be necessary to avoid operational disruptions at the coal-fired generating units. Reliability of coal deliveries can be affected periodically 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 2011 and beyond and normally augments its coal supply agreements with spot market purchases. The Company 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, Ohio and Wyoming for the foreseeable future. This supply, in combination with the installation of FGDs (SO_2 removal systems), KU expects its use of higher sulfur coal to increase, the combination of which is expected to enable KU to continue to provide electric service in compliance with existing environmental laws and regulations. Coal is delivered to KU's generating stations by a mix of transportation modes, including barge, truck and rail.

Seasonality

Demand for and market prices for electricity are affected by weather. As a result, KU's overall operating results in the future may fluctuate substantially on a seasonal basis, especially when more severe weather conditions such as heat waves or winter storms make such fluctuations more pronounced. The pattern of this fluctuation may change depending on the type and location of the facilities KU owns and the terms of its contracts to purchase or sell electricity.

Environmental Matters

General

Protection of the environment is a major priority for KU and a significant element of its business activities. KU's properties and operations are subject to extensive environmental-related oversight by federal, state and local regulatory agencies, including via air quality, water quality, waste management and similar laws and regulations. Therefore, KU must conduct its operations in accordance with numerous permit and other requirements issued under or contained in such laws or regulations.

Climate Change

Recent developments continue to indicate an increased possibility of significant climate change or GHG legislation or regulation, at the international, federal, regional and state levels. During December 2009, as part of the United Nation's Copenhagen Accord, the United States agreed to a non-binding goal to reduce GHG emissions to 17% below 2005 levels by 2020. Additionally, during 2009, the U.S. House of Representatives passed comprehensive GHG legislation, which included a number of measures to limit GHG emissions and achieve GHG emission reduction targets below 2005 levels of 3% by 2012, 17% by 2020 and 83% by 2050. Similar legislation has been considered in the U.S. Senate, but the prospects for passage remain uncertain. In late 2009, the EPA issued a final endangerment finding relating to mobile sources of GHGs and a GHG reporting requirement beginning in 2010. In 2010, the EPA issued a final rule requiring implementation of best available control technology for GHG emissions from new or modified power plants, effective January 2011. In December 2010, the EPA announced that it intends to propose New Source Performance Standards addressing GHG emissions from new and existing power plants, with a proposed rule expected in July 2011. Finally, a number of U.S. states, although not currently including Kentucky, have adopted GHG-reduction legislation or regulation of various sorts. The developing GHG initiatives include a number of differing structures and formats, including direct limitations on GHG sources, issuance of allowances for GHG emissions, cap-and-trade programs for such allowances, renewable or alternative generation portfolio standards and mechanisms relating to demand reduction, energy efficiency, smart-grid, transmission expansion, carbon-sequestration or other GHG-reducing efforts. While the final terms and impacts of such initiatives cannot be estimated, KU, as a primarily coal-fired utility, could be highly affected by such proceedings.

Among other emissions, GHGs include carbon-dioxide, which is produced via the combustion of fossil fuels such as coal and natural gas. KU's generating fleet is approximately 66% coal-fired, 34% oil/natural gas-fired and less than 1% hydroelectric based on capacity. During 2010, KU produced approximately 98% of its electricity from coal, 2% from natural gas combustion and less than 1% from hydroelectric generation, based on Mwh. During 2010, KU's emissions of GHGs were approximately 16.4 million metric tons of carbon-dioxide equivalents from KU's owned or controlled generation sources. While its generation activities account for the bulk of its GHG emissions, other GHG sources at KU include operation of motor vehicles and powered equipment, leakage or evaporation associated with natural gas pipelines, refrigerating equipment and similar activities.

Ultimately, environmental matters or potential environmental matters can represent an important element of current or future potential capital requirements, future unit retirement or replacement decisions, supply and demand for electricity, operating and maintenance expenses or compliance risks for the Company. Based on prior regulatory precedent, KU currently anticipates that many of such direct costs may be recoverable through rates or other regulatory mechanisms, particularly with respect to coal-related generation, but the availability, timing or completeness of such rate recovery cannot be assured. Ultimately, climate change and other environmental matters will likely increase the level of capital expenditures and operating and maintenance costs incurred by the Company during the next several years. With respect to NAAQS, CATR, CAMR replacement and coal combustion byproducts developments, based on a preliminary analysis of proposed regulations, the Company may be required to consider actions such as upgrading existing emissions controls, installing additional emissions controls, upgrading byproducts disposal and storage and possible early replacement of coal-fired units. In order to comply with the coal combustion residual rules and the above referenced air rules, capital expenditures for KU are preliminarily estimated to be in the $1.5 to $1.7 billion range over the next ten years, although final costs may substantially vary. This estimate does not include compliance with GHG rules or contemplated water-related environmental changes. See Risk Factors, Management's Discussion and Analysis and Note 13, Commitments and Contingencies, for further information.

State Executive or Legislative Matters

In November 2008, the Commonwealth of Kentucky issued an action plan to create efficient, sustainable energy solutions and strategies and move toward state energy independence. The plan outlines the following seven strategies to work toward these goals:

- Improve the energy efficiency of Kentucky's homes, buildings, industries and transportation fleet
- Increase Kentucky's use of renewable energy
- Sustainably grow Kentucky's production of biofuels
- Develop a coal-to-liquids industry in Kentucky to replace petroleum-based liquids
- Implement a major and comprehensive effort to increase natural gas supplies, including coal-to-natural gas in Kentucky
- Initiate aggressive carbon capture/sequestration projects for coal-generated electricity in Kentucky
- Examine the use of nuclear power for electricity generation in Kentucky

In December 2009, the Governor of Kentucky's Executive Task Force on Biomass and Biofuels issued a final report to establish potential strategic actions to develop biomass and biofuels industries in Kentucky. The plan noted the potential importance of biomass as a renewable energy source available to Kentucky and discussed various goals or mechanisms, such as the use of approximately 25 million tons of biomass for generation fuel annually, allotment of electricity and natural gas taxes and state tax credits to support biomass development.

In January 2010, a state-established Kentucky Climate Action Plan Council (the "Council") commenced formal activities. The Council, which includes governmental, industry, consumer and other representatives, seeks to identify possible Kentucky responses to potential climate change and federal legislation, including increasing statewide energy efficiency, energy independence and economic growth. The Council has established various technical work groups, including in the areas of energy supply and energy efficiency/conservation, to provide input, data and recommendations.

During the current session of the Kentucky General Assembly, as during prior legislative sessions, legislators have introduced or are expected to introduce various bills with respect to environmental or utility matters, including potential requirements relating to renewable energy portfolios, energy conservation measures, coal mining or coal byproduct operations and other matters. The current session is scheduled to end in March 2011 and until such time the prospects and final terms of any such legislation cannot be determined. Legislative and regulatory actions as a result of these proposals and their impact on KU, which may be significant, cannot currently be predicted.

Franchises and Licenses

KU provides electric delivery service in its various service areas pursuant to certain franchises, licenses, statutory service areas, easements and other rights or permissions granted by state legislatures, cities or municipalities or other entities.

Competition

There are currently no other electric utilities operating within the electric service areas of KU. 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 any legislative or regulatory actions regarding industry restructuring and their impact on KU, which may be significant, cannot currently be predicted. Virginia, formerly a competitive jurisdiction, has enacted legislation which implements a hybrid model of cost-based regulation. See Note 3, Rates and Regulatory Matters, for further information.

Employees and Labor Relations

KU had 974 employees at December 31, 2010, consisting of 973 full-time employees and 1 part-time employee. Of the total employees, 145, or 15%, were operating, maintenance and construction employees represented by the IBEW Local 2100 and the United Steelworkers of America ("USWA") Local 9447-01. In August 2009, the Company and its employees represented by the IBEW Local 2100 entered into a three-year collective bargaining agreement that provides for negotiated increases or changes to wages, benefits or other provisions and annual wage re-openers. In August 2008, the Company and its employees represented by the USWA Local 9447-01 entered into a three-year collective bargaining agreement that provides for negotiated increases or changes to wages, benefits or other provisions and annual wage re-openers.

Officers of the Company

Officers are elected annually by the Board of Directors. There are no family relationships among any of the executive officers, nor is there any arrangement or understanding between any executive officer and any other person pursuant to which the officer was selected.

Except as may be set forth in Legal Proceedings, there have been no events under any bankruptcy act, no criminal proceedings and no judgments or injunctions material to the evaluation of the ability and integrity of any executive officer during the past five years.

Listed below are the executive officers at December 31, 2010.

Name	Age	Positions Held During the Past Five Years	Dates
Victor A. Staffieri	55	Chairman of the Board, President and Chief Executive Officer	May 2001 – present
John R. McCall	67	Executive Vice President, General Counsel, Corporate Secretary and Chief Compliance Officer	July 1994 – present
Chris Hermann	63	Senior Vice President – Energy Delivery	February 2003 – present
Paula H. Pottinger	53	Senior Vice President – Human Resources	January 2006 – present
S. Bradford Rives	52	Chief Financial Officer	September 2003 – present
Paul W. Thompson	53	Senior Vice President – Energy Services	June 2000 – present

Officers generally serve in the same capacities at the Company, LKE and LG&E.

Risk Factors

Any of the events or circumstances described as risks below could result in a significant or material adverse effect on the business, results of operations, cash flows or financial condition. The risks and uncertainties described below may not be the only risks and uncertainties that KU faces. Additional risks and uncertainties not currently known or that KU currently deems immaterial may also result in a significant or material adverse effect on the business, results of operations, cash flow or financial condition.

KU's business is subject to significant and complex governmental regulation.

Various federal and state entities, including but not limited to the FERC, Kentucky Commission, Virginia Commission and the Tennessee Regulatory Authority, regulate many aspects of utility operations of KU, including the following:

- the rates that KU may charge and the terms and conditions of the Company's service and operations;
- financial and capital structure matters;
- siting and construction of facilities;
- mandatory reliability and safety standards and other standards of conduct;
- accounting, depreciation and cost allocation methodologies;
- tax matters;
- affiliate restrictions;
- acquisition and disposal of utility assets and securities; and
- various other matters.

Such regulations or changes thereto 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 rate requests and ultimately reduce, alter or limit the rates the Company seeks.

The profitability of KU is highly dependent on its ability to recover the costs of providing energy and utility services to its customers and earn an adequate return on its capital investments. KU currently provides services to retail customers at rates approved by one or more federal or state regulatory commissions, including those commissions referred to above. While these rates are generally regulated based on an analysis of their costs incurred in a base year, the rates KU is allowed to charge may or may not match its costs at any given time. While rate regulation is premised on providing a reasonable opportunity to earn a reasonable rate of return on invested capital, there can be no assurance that the applicable regulatory commissions will consider all of the costs to have been prudently incurred or that the regulatory process in which rates are determined will always result in rates that will produce full recovery of KU's costs or an adequate return on KU's capital investments. If the Company's costs are not adequately recovered through rates, it could have an adverse affect on the business, results of operations, cash flows or financial condition.

As part of the PPL acquisition commitments, KU has agreed, subject to certain limited exceptions such as fuel and environmental cost recoveries, that no base rate increase would take effect for Kentucky retail customers before January 1, 2013.

Transmission and interstate market activities of KU, as well as other aspects of the business, are subject to significant FERC regulation.

KU is subject to extensive regulation by the FERC covering matters including rates charged to transmission users, market-based or cost-based rates applicable to 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, including but not limited to the areas of market-based tariff authority, RSG resettlements in the MISO market, mandatory reliability standards and natural gas transportation regulation can affect the earnings, operations or other activities of KU.

Changes in transmission and wholesale power market structures could increase costs or reduce revenues.

Wholesale sales fluctuate with regional demand, fuel prices and contracted capacity. Changes to transmission and wholesale power market structures and prices may occur in the future, are not estimable and may result in unforeseen effects on energy purchases and sales, transmission and related costs or revenues. These can include commercial or regulatory changes affecting power pools, exchanges or markets in which KU participates.

KU undertakes significant capital projects and these activities are subject to unforeseen costs, delays or failures, as well as risk of inadequate recovery of resulting costs.

KU's business is capital intensive and requires significant investments in energy generation and distribution and other infrastructure projects, such as projects for environmental compliance. The completion of these projects without delays or cost overruns is subject to risks in many areas, including the following:

- approval, licensing and permitting;
- land acquisition and the availability of suitable land;
- skilled labor or equipment shortages;
- construction problems or delays, including disputes with third party intervenors; increases in commodity prices or labor rates;
- contractor performance;
- environmental considerations and regulations;
- weather and geological issues; and
- political, labor and regulatory developments.

Failure to complete capital projects on schedule or on budget, or at all, could adversely affect the Company's financial performance, operations and future growth.

The costs of compliance with, and liabilities under, environmental laws are significant and are subject to continual changes.

Extensive federal, state and local environmental laws and 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 but could be material. In addition, KU's costs may increase significantly if the requirements or scope of environmental laws or regulations, or similar rules, are expanded or changed from prior versions by the relevant agencies. Costs may take the form of increased capital or operating and maintenance expenses; monetary fines, penalties or forfeitures or other restrictions. Many of these environmental law considerations are also applicable to the operations of key suppliers, or customers, such as coal producers, industrial power users, etc., and may impact the costs of their products or their demand for KU's services.

KU is subject to operational and financial risks regarding certain on-going developments concerning environmental regulation.

A number of regulatory initiatives have been implemented or are under development which could have the effect of significantly increasing the environmental regulation or operational or compliance costs related to a number of emissions or operating activities which are associated with the combustion of coal as occurs at the Company's generating stations. Such developments could include potential new or revised federal or state legislation or regulation regarding emissions of NOx, SO_2, mercury and other particulates generally and regarding storage of coal combustion byproducts. Additional regulatory initiatives may occur in other areas involving the Company's operations, including revision of limitations on water discharge or intake activities or increased standards relating to polychlorinated biphenyl usage. Compliance with any new laws or regulations in these matters could result in significant changes to KU's operations, significant capital expenditures by the Company or significant increases in the cost of conducting business.

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 other factors can significantly affect the finances or operations of KU by changing demand levels; causing outages; damaging infrastructure or requiring significant repair costs; affecting capital markets and general economic conditions or impacting future growth.

KU is subject to operational and financial risks regarding potential developments concerning global climate change.

Various regulatory and industry initiatives have been implemented or are under development to regulate or otherwise reduce emissions of GHGs, which are emitted from the combustion of fossil fuels such as coal and natural gas, as occurs at the Company's generating stations. Such developments could include potential federal or state legislation or industry initiatives allocating or limiting GHG emissions; establishing costs or charges on GHG emissions or on fuels relating to such emissions; requiring GHG capture and sequestration; establishing renewable portfolio standards or generation fleet-diversification requirements to address GHG emissions; promoting energy efficiency and conservation; changes in transmission grid construction, operation or pricing to accommodate GHG-related initiatives; or other measures. The generation fleet of KU is predominantly coal-fired and may be highly impacted by developments in this area. Compliance with any new laws or regulations regarding the reduction of GHG emissions could result in significant changes to KU's operations, significant capital expenditures by the Company and a significant increase in the cost of conducting business. KU may face strong competition for, or difficulty in obtaining, required GHG-compliance related goods and services, including construction services, emissions allowances and financing, insurance and other inputs relating thereto. Increases in KU's costs or prices of producing or selling electric power due to GHG-related developments could materially reduce or otherwise affect the demand, revenue or margin levels applicable to its power, thus adversely affecting its financial condition or results of operations.

KU is subject to physical, market and economic risks relating to potential effects of climate change.

Climate change may produce changes in weather or other environmental conditions, including temperature or precipitation changes, such as warming or drought. These changes may affect farm and agriculturally-dependent businesses and activities, which are an important part of Kentucky's economy, and thus may impact consumer demand for electric power. Temperature increases could result in increased overall electricity volumes or peaks and precipitation changes could result in altered availability of water for plant cooling operations. These or other meteorological changes could lead to increased operating costs, capital expenses or power purchase costs by KU. Conversely, climate change could have a number of potential impacts tending to reduce demand. Changes may entail more frequent or more intense storm activity, which, if severe, could temporarily disrupt regional economic conditions and adversely affect electricity demand levels. As discussed in other risk factors, storm outages and damage often directly decrease revenues or increase expenses, due to reduced usage and higher restoration charges, respectively. GHG regulation could increase the cost of electric power, particularly power generated by fossil fuels, and such increases could have a depressive effect on the regional economy. Reduced economic and consumer activity in the service area of KU, both in general and specific to certain industries and consumers accustomed to previously low-cost power, could reduce demand for KU's electricity. Also, demand for services could be similarly lowered should consumers' preferences or market factors move toward favoring energy efficiency, low-carbon power sources or reduced electric usage generally.

The business of KU is subject to risks associated with local, national and worldwide economic conditions.

The consequences of prolonged recessionary conditions may include a lower level of economic activity and uncertainty or volatility regarding energy prices and the capital and commodity markets. A lower level of economic activity might result in a decline in energy consumption, unfavorable changes in energy and commodity prices and slower customer growth, which may adversely affect KU's future revenues and growth. Instability in the financial markets, as a result of recession or otherwise, also may affect the cost of capital and the ability to raise capital. A deterioration of economic conditions may lead to decreased production by KU's industrial customers and, therefore, lower consumption of electricity. Decreased economic activity may also lead to fewer commercial and industrial customers and increased unemployment, which may in turn impact residential customers' ability to pay. Further, worldwide economic activity has an impact on the demand for basic commodities needed for utility infrastructure. Changes in global demand may impact the ability to acquire sufficient supplies and the cost of those commodities may be higher than expected.

KU's business is concentrated in the Midwest United States, specifically Kentucky and Virginia.

Although the business of KU is concentrated in Kentucky and Virginia, it also operates in Tennessee. Local and regional economic conditions, such as population growth, industrial growth, expansion and economic development or employment levels, as well as the operational or financial performance of major industries or customers, can affect the demand for energy and KU's results of operations. Significant industries and activities in the service area of KU include aluminum and steel smelting and fabrication; chemical processing; coal, mineral and ceramic related activities; educational institutions; health care facilities; paper and pulp processing; metal fabrication; and water and sewer utilities. Any significant downturn in these industries or activities or in local and regional economic conditions in KU's service area may adversely affect the demand for electricity in the service area.

KU is subject to operational risks relating to KU's generating plants, transmission facilities, distribution equipment, information technology systems and other assets and activities.

Operation of power plants, transmission and distribution facilities, information technology systems and other assets and activities subjects KU to many risks, including the breakdown or failure of equipment; accidents; security breaches, viruses or outages affecting information technology systems; labor disputes; obsolescence; delivery/transportation problems and disruptions of fuel supply and performance below expected levels. Occurrences of these events may impact the ability of KU to conduct its business efficiently or lead to increased costs, expenses or losses.

Although KU maintains customary insurance coverage for certain of these risks common to utilities, it does not have insurance covering the transmission and distribution systems, other than substations, because it has found the cost of such insurance to be prohibitive. If KU is unable to recover the costs incurred in restoring transmission and distribution properties following damage resulting from ice storms, tornados or other natural disasters or to recover the costs of other liabilities arising from the risks of its business, through a change in rates or otherwise, or if such recovery is not received on a timely basis, it may not be able to restore losses or damages to its properties without an adverse effect on its financial condition, results of operations or its reputation.

KU is subject to liability risks relating to its generation, transmission, distribution and retail businesses.

The conduct of the physical and commercial operations of KU subjects it to many risks, including risks of potential physical injury, property damage or other financial affects, caused to or caused by employees, customers, contractors, vendors, contractual or financial counterparties and other third parties.

KU could be negatively affected by rising interest rates, downgrades to bond credit ratings or other negative developments in its ability to access câpital markets.

In the ordinary course of business, KU is reliant upon adequate long-term and short-term financing means to fund significant capital expenditures, debt interest or maturities and operating needs. As a capital-intensive business, the Company is sensitive to developments in interest rate levels; credit rating considerations; insurance, security or collateral requirements; market liquidity and credit availability and refinancing steps necessary or advisable to respond to credit market changes. Changes in these conditions could result in increased costs and decreased liquidity available to the Company.

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 the Company.

KU is subject to risks associated with defined benefit retirement plans, health care plans, wages and other employee-related matters.

KU sponsors pension and postretirement benefit plans for its employees. Risks with respect to these plans include adverse developments in legislation or regulation, future costs or funding levels, returns on investments, market fluctuations, interest rates and actuarial matters. Changes in health care rules, market practices or cost structures can affect current or future funding requirements or liabilities. Without sustained growth in respective investments over time to increase the value of plan assets, KU could be required to fund plans with significant amounts of cash. KU is also subject to risks related to 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.

KU is subject to risks associated with federal and state tax regulations.

Changes in taxation as well as the inherent difficulty in quantifying potential tax effects of business decisions could negatively impact results of operations. KU is required to make judgments in order to estimate its obligations to taxing authorities. These tax obligations include income, property, sales and use and employment-related taxes. KU also estimates its ability to utilize tax benefits and tax credits. Due to the revenue needs of the states and jurisdictions in which KU operates, various tax and fee increases may be proposed or considered. KU cannot predict whether legislation or regulation will be introduced or the effect on the Company of any such changes. If enacted, any changes could increase tax expense and could have a negative impact on its results of operations and cash flows.

Legal Proceedings

Rates and Regulatory Matters

For a discussion of current rates and regulatory matters, including recent electric base rate increase proceedings, rate commitments in change-of-control proceedings, TC2 proceedings, FERC, Kentucky Commission and Virginia Commission proceedings and other rates or regulatory matters affecting KU, see Note 3, Rates and Regulatory Matters, and Note 13, Commitments and Contingencies.

Environmental

For a discussion of environmental matters, including potential coal combustion byproduct or ash pond regulation; additional reductions in SO_2, NOx and other regulated emissions; NOVs and other emissions proceedings; environmental permit challenges; and other environmental items affecting KU, see Risk Factors, Note 3, Rates and Regulatory Matters, and Note 13, Commitments and Contingencies.

Climate Change

For a discussion of matters relating to potential climate change, GHG emission or global warming developments, including increased legislative and regulatory activity which could limit or increase costs applicable to fossil fuel generation sources, legal proceedings claiming damages relating to global warming, GHG reporting requirements and other matters, see Business, Risk Factors, Management's Discussion and Analysis and Note 13, Commitments and Contingencies.

Litigation

In connection with an administrative proceeding alleging a violation by a former Argentine affiliate under that country's 2002-2003 emergency currency exchange laws, claims are pending against the affiliate's then directors, including two individuals who are executive officers of the Company, in a specialized Argentine financial criminal court. Under applicable Argentine laws, directors of a local company may be liable for monetary penalties for a subject company's violations of the currency laws. The affiliate and the relevant executive officers believe their actions were in compliance with the relevant laws and have presented defenses in the administrative and criminal proceedings. LKE has standard indemnification arrangements with its executive officers. The former affiliate is now owned by a third party, which has agreed to indemnify LKE and the relevant executive officers.

For a discussion of litigation matters, see Note 13, Commitments and Contingencies.

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, the Company 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

Dollars are in millions unless otherwise noted.

	Successor	Predecessor				
	November 1, 2010 through December 31, 2010	January 1, 2010 through October 31, 2010	Year Ended December 31, 2009	2008	2007	2006
Operating revenues	$ 263	$ 1,248	$ 1,355	$ 1,405	$ 1,272	$ 1,210
Operating income	$ 65	$ 285	$ 269	$ 260	$ 267	$ 235
Net income	$ 35	$ 140	$ 133	$ 158	$ 167	$ 152
Total assets	$ 6,059	$ 5,145	$ 4,956	$ 4,518	$ 3,796	$ 3,148
Long-term debt obligations (including amounts due within one year)	$ 1,841	$ 1,682	$ 1,682	$ 1,532	$ 1,264	$ 843

Management's Discussion and Analysis and Notes to Financial Statements should be read in conjunction with the above information.

Management's Discussion and Analysis

Management's Discussion and Analysis should be read in conjunction with the Financial Statements and Notes for the years ended December 31, 2010, 2009 and 2008. Dollars are in millions unless otherwise noted.

The purpose of "Management's Discussion and Analysis" is to provide information about KU's performance in implementing its' strategies and managing risks and challenges. Specifically:

- "Overview" provides background regarding KU's business and identifies significant matters with which management is primarily concerned in evaluation of KU's financial condition and operating results.
- "Results of Operations" provides a description of KU's operating results in 2010, 2009 and 2008, including a review of earnings and a brief outlook for 2011.
- "Financial Condition" provides an analysis of KU's liquidity position and credit profile, including its sources of cash (including bank credit facilities and sources of operating cash flow) and uses of cash (including contractual obligations and capital expenditure requirements) and the key risks and uncertainties that impact KU's past and future liquidity position and financial condition. This subsection also includes a discussion of KU's current credit ratings.
- "Application of Critical Accounting Policies and Estimates" provides an overview of the accounting policies that are particularly important to the results of operations and financial condition of KU and that require its management to make significant estimates, assumptions and other judgments.

Overview

KU is a regulated utility engaged in the generation, transmission, distribution and sale of electric energy in Kentucky, Virginia and Tennessee. See the Business section for a description of the business. The rates KU charges its customers requires approval of the appropriate regulatory government agency. See Note 3, Rates and Regulatory Matters, for information regarding rate cases, regulatory assets and liabilities and other regulatory matters.

KU and its affiliate, LG&E, are wholly owned subsidiaries of LKE, a Kentucky limited liability company. PPL acquired LKE on November 1, 2010. Headquartered in Allentown, Pennsylvania, PPL is an energy and utility holding company that was incorporated in 1994. Through its subsidiaries, PPL owns or controls about 19,000 megawatts of generating capacity in the U.S., sells energy in key U.S. markets and delivers electricity and natural gas to about 5.3 million customers in the U.S. and the U.K. Following the acquisition, both KU and LG&E continue operating as subsidiaries of LKE, which is now an intermediary holding company in the PPL group of companies. See Note 2, Acquisition by PPL, for further information regarding the acquisition.

In operating its business, the Company faces several risks including credit risks, liquidity risks, interest rate risks and commodity and price risks. For instance, the Company has credit risks from counterparties, customers and effects of its' own credit ratings. KU attempts to manage these risks through the adoption of financial and operational risk management programs that, among other things, are designed to monitor and reduce its' exposure to these risks. Identified within "Management's

Discussion and Analysis" of "Financial Condition" and "Results of Operations" are risks KU's management currently consider material; these risks are not the only risks faced by KU. Additional risks not presently known or currently deemed immaterial may also impair KU's business operations. See Risk Factors and Financial Condition - Risk Management for further discussion.

Predecessor and Successor Financial Presentation

KU's financial statements and related financial and operating data include the periods before or after PPL's acquisition of LKE on November 1, 2010, and are labeled as Predecessor or Successor. KU applied push-down accounting to account for the acquisition. For accounting purposes only, push-down accounting is considered to create a new entity due to new cost basis assigned to assets, liabilities and equity as of the acquisition date. Consequently, KU's results of operations and cash flows for the Predecessor and Successor periods in 2010 are shown separately, rather than combined, in its audited financial statements.

In the "Management's Discussion and Analysis" of "Results of Operations" and "Financial Condition", the Company has included disclosure of the combined Predecessor and Successor results of operations and cash flows. Such presentation is considered to be a non-GAAP disclosure. KU has included such disclosure because the Company believes it facilitates the comparison of 2010 operating and financial performance to 2009 and 2008, and because the core operations of the Company have not changed as a result of the acquisition.

Competition

See the Business section for information concerning competition.

Environmental Matters

General

Protection of the environment is a major priority for KU and a significant element of its business activities. Extensive federal, state and local environmental laws and 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 but could be material. In addition, costs may increase significantly if the requirements or scope of environmental laws or regulations, or similar rules, are expanded or changed from prior versions by the relevant agencies. Costs may take the form of increased capital or operating and maintenance expenses; monetary fines, penalties or forfeitures or other restrictions. Many of these environmental law considerations are also applicable to the operations of key suppliers, or customers, such as coal producers, industrial power users, etc., and may impact the costs of their products or their demand for KU's services.

Climate Change

Recent developments continue to indicate an increased possibility of significant climate change or GHG legislation or regulation, at the international, federal, regional and state levels. During December 2009, as part of the United Nation's Copenhagen Accord, the United States agreed to a non-binding goal to reduce GHG emissions to 17% below 2005 levels by 2020. Additionally, during 2009, the U.S. House of

Representatives passed comprehensive GHG legislation, which included a number of measures to limit GHG emissions and achieve GHG emission reduction targets below 2005 levels of 3% by 2012, 17% by 2020 and 83% by 2050. Similar legislation has been considered in the U.S. Senate, but the prospects for passage remain uncertain. In late 2009, the EPA issued a final endangerment finding relating to mobile sources of GHGs and a GHG reporting requirement beginning in 2010. In 2010, the EPA issued a final rule requiring implementation of best available control technology for GHG emissions from new or modified power plants, effective January 2011. In December 2010, the EPA announced that it intends to propose New Source Performance Standards addressing GHG emissions from new and existing power plants, with a proposed rule expected in July 2011. Finally, a number of U.S. states, although not currently including Kentucky, have adopted GHG-reduction legislation or regulation of various sorts. The developing GHG initiatives include a number of differing structures and formats, including direct limitations on GHG sources, issuance of allowances for GHG emissions, cap-and-trade programs for such allowances, renewable or alternative generation portfolio standards and mechanisms relating to demand reduction, energy efficiency, smart-grid, transmission expansion, carbon-sequestration or other GHG-reducing efforts. While the final terms and impacts of such initiatives cannot be estimated, KU, primarily a coal-fired utility, could be highly affected by such proceedings.

Other Environmental Regulatory Initiatives

The EPA has proposed or announced that it intends to propose a number of additional environmental regulations that could substantially impact utilities with coal-fired generating assets. These regulatory initiatives include revisions to the ambient air quality standards for SO_2, NO_2, ozone and particulate matter 2.5 microns in size or less, rules aimed at mitigating the interstate transport of SO_2 and NOx, a program governing emissions of hazardous air pollutants from utility generating units, a program for the management of coal combustion residuals, revised effluent guidelines for utility generating facilities and standards for cooling water intake structures. Such requirements could potentially mandate upgrade of existing emission controls, installation of additional emission controls such as FGDs, SCRs, fabric filter bag houses, activated carbon injection, wet electrostatic precipitators, closure of ash ponds and retrofit of landfills, installation of cooling towers, deployment of new water treatment technologies and retirement of facilities that cannot be retrofitted on a cost effective basis.

The cost to KU and the effect on KU's business of complying with potential GHG restrictions and other environmental regulatory initiatives will depend upon provisions of any final rules and how the rules are implemented by the EPA. Some of the design elements which may have the greatest effect on KU include (a) the required levels and timing of emissions caps, discharge limits or similar standards, (b) the sources covered by such requirements, (c) transition and mitigation provisions, such as phase-in periods, free allowances or price caps, (d) the availability and pricing of relevant mitigation or control technologies, goods or services and (e) economic, market and customer reaction to electricity price and demand changes due to environmental concerns.

Ultimately, environmental matters or potential environmental matters can represent an important element of current or future potential capital requirements, future unit retirement or replacement decisions, supply and demand for electricity, operating and maintenance expenses or compliance risks for the Company. Based on prior regulatory precedent, KU currently anticipates that many of such direct costs may be recoverable through rates or other regulatory mechanisms, particularly with respect to coal-related generation, but the availability, timing or completeness of such rate recovery cannot be assured. Ultimately, climate change and other environmental matters will likely increase the level of capital expenditures and operating and maintenance costs incurred by the Company during the next several years. With respect to NAAQS, CATR, CAMR replacement and coal combustion byproducts developments, based on a preliminary analysis of proposed regulations, the Company may be required to consider actions such as upgrading existing emissions controls, installing additional emissions controls, upgrading byproducts disposal and storage and possible early replacement of coal-fired units. In order to comply with the coal combustion residual rules and the above referenced air rules, capital expenditures for KU are preliminarily estimated to be in the $1.5 to $1.7 billion range over the next ten years, although final costs may substantially vary. This estimate does not include compliance with GHG rules or contemplated water-related environmental changes. See Risk Factors and Note 13, Commitments and Contingencies, for further information.

Results of Operations

The utility business is affected by seasonal temperatures. As a result, operating revenues (and associated operating expenses) are not generated evenly throughout the year. Revenue and earnings are generally highest during the first and third quarters, and lowest in the second quarter, due to weather.

Net Income

The following table summarizes the significant components of net income for 2010, 2009 and 2008 and the changes therein:

	Combined	Successor	Predecessor		
	Year Ended December 31, 2010	November 1, 2010 through December 31, 2010	January 1, 2010 through October 31, 2010	Year Ended December 31, 2009	Year Ended December 31, 2008
Total operating revenues	$ 1,511	$ 263	$ 1,248	$1,355	$ 1,405
Total operating expenses	1,161	198	963	1,086	1,145
Operating income	350	65	285	269	260
Equity in earnings of unconsolidated venture	3	-	3	1	30
Interest expense	14	8	6	6	14
Interest expense to affiliated companies	64	2	62	69	58
Other income (expense) – net	(2)	-	(2)	5	8
Income before income taxes	273	55	218	200	226
Income tax expense	98	20	78	67	68
Net income	$ 175	$ 35	$ 140	$ 133	$ 158

The change in KU's net income was as follows:

	Increase (Decrease)	
	2010 vs. 2009	2009 vs. 2008
Total operating revenues	$ 156	$ (50)
Total operating expenses	75	(59)
Operating income	81	9
Equity in earnings of unconsolidated venture	2	(29)
Interest expense	8	(8)
Interest expense to affiliated companies	(5)	11
Other income (expense) – net	(7)	(3)
Income (loss) before income taxes	73	(26)
Income taxes	31	(1)
Net income	$ 42	$ (25)

Operating Revenues

The $156 million increase from 2009 to 2010 and $50 million decrease from 2008 to 2009 in operating revenues were primarily due to:

	Increase (Decrease)	
	2010 vs. 2009	2009 vs. 2008
Retail sales volumes (a)	$ 73	$ (43)
Base rate price variance (b)	39	(5)
Demand revenue (c)	16	(1)
Sales to municipal customers (d)	12	(1)
Increased recoverable capital spending billed through the ECR	8	50
Other operating revenue primarily due to late payment charges	6	6
FAC price variance (e)	5	(2)
Merger surcredit termination in February 2009	2	13
Transmission sales	1	-
Increased recoverable program spending billed through the DSM	1	9
Wholesale sales (f)	(7)	(77)
VDT surcredit termination in August 2008	-	1
	$ 156	$ (50)

(a) Retail sales volumes increased during 2010 compared to 2009 as a result of increased consumption primarily due to increased heating degree days during the first and fourth quarters of 2010 and increased cooling degree days during the second and third quarters of 2010. Additionally, improved economic conditions in 2010 and significant storm outages in 2009 contributed to the increased volumes.

The decrease in retail sales volumes during 2009 compared to 2008 was attributable to reduced consumption by retail customers, as a result of milder weather and weakened economic conditions, in addition to significant storm outages during 2009.

(b) The increase in revenues due to the base rate price variance during 2010 compared to 2009 resulted from higher base rates effective August 1, 2010. See Note 3, Rates and Regulatory Matters, for further discussion of the 2010 Kentucky rate case.

The decrease in revenues due to the base rate price variance during 2009 compared to 2008 resulted from a reduction in base energy rates effective February 6, 2009. See Note 3, Rates and Regulatory Matters, for further discussion of the 2008 Kentucky rate case.

(c) Demand revenues increased during 2010 compared to 2009 as a result of higher demand rates effective August 1, 2010 and higher customer peak demand. See Note 3, Rates and Regulatory Matters, for further discussion of the 2010 Kentucky rate case.

(d) The increase in sales to municipal customers during 2010 compared to 2009 was primarily due to increased volumes as a result of increased cooling and heating degree days, improved economic conditions and a decline in storm outages.

(e) FAC revenues increased during 2010 compared to 2009 as a result of increased recoverable fuel costs billed to customers through the FAC due to higher fuel prices.

The decrease in the FAC revenue during 2009 compared to 2008 resulted from lower fuel costs billed to customers through the FAC ($2 million) due to a refund of power purchased costs from OMU ($6 million) partially offset by increased recoverable fuel costs ($4 million) billed to retail customers through the FAC.

(f) The decrease in wholesale sales during 2010 compared to 2009 was primarily due to increased consumption by industrial customers, as a result of improved economic conditions, increased consumption by residential customers, as a result of increased cooling and heating degree days and an increase in LG&E's coal-fired generation outages in the first six months of 2010. See Note 15, Related Party Transactions, for further discussion of the mutual agreement for wholesale sales and purchases between KU and LG&E.

The decrease in wholesale sales during 2009 compared to 2008 was primarily due to lower sales volumes to LG&E and third-parties due to lower economic capacity, caused by low spot market pricing and higher scheduled coal-fired generation outages. See Note 15, Related Party Transactions, for further discussion of the mutual agreement for wholesale sales and purchases between KU and LG&E.

Operating 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 FERC, Kentucky Commission, Virginia Commission and the Tennessee Regulatory Authority. Operating expenses and the changes therein for 2010, 2009 and 2008 follow:

	Combined	Successor	Predecessor		
	Year Ended December 31, 2010	November 1, 2010 through December 31, 2010	January 1, 2010 through October 31, 2010	Year Ended December 31, 2009	Year Ended December 31, 2008
Fuel for electric generation	$ 495	$ 78	$ 417	$ 434	$ 513
Power purchased	175	28	147	199	221
Other operation and maintenance expenses	346	66	280	320	275
Depreciation and amortization	145	26	119	133	136
	$ 1,161	$ 198	$ 963	$ 1,086	$ 1,145

The changes in operating expenses were as follows:

	Increase (Decrease) 2010 vs. 2009	Increase (Decrease) 2009 vs. 2008
Fuel for electric generation	$ 61	$ (79)
Power purchased	(24)	(22)
Other operation and maintenance expenses	26	45
Depreciation and amortization	12	(3)
	$ 75	$ (59)

Fuel for Electric Generation

The $61 million increase from 2009 to 2010 and $79 million decrease from 2008 to 2009 were primarily due to:

	Increase (Decrease) 2010 vs. 2009	Increase (Decrease) 2009 vs. 2008
Fuel usage volumes (a)	$ 77	$ (97)
Commodity costs for coal	(15)	18
Other	(1)	-
	$ 61	$ (79)

(a) Fuel usage volumes increased in 2010 compared 2009 due to increased native load sales. Fuel usage volumes decreased in 2009 compared to 2008 due to decreased native load and wholesale sales.

Power Purchased Expense

The $24 million decrease from 2009 to 2010 and $22 million decrease from 2008 to 2009 were primarily due to:

	Increase (Decrease)	
	2010 vs. 2009	2009 vs. 2008
Power purchased from OMU	$ (40)	$ 12
Purchases from LG&E due to volume (a)	(5)	(2)
Demand payments for third party purchases	(2)	1
Prices for purchases used to serve retail customers	7	(14)
Third party purchased volumes for native load (b)	7	(6)
OMU settlement received in 2009	6	(6)
Purchases from LG&E due to prices	3	(7)
	$ (24)	$ (22)

(a) Purchased volumes from LG&E decreased in 2010 compared to 2009 primarily due to increased consumption by residential customers at LG&E as the result of increased cooling and heating degree days, increased coal-fired generation outages in the first six months of 2010 and higher energy usage by industrial customers as a result of improved economic conditions.

Purchased volumes from LG&E decreased in 2009 compared to 2008 due to LG&E's increased scheduled outages at coal-fired generation units during the fourth quarter of 2009. See Note 15, Related Party Transactions, for further discussion of the mutual agreement for wholesale sales and purchases between the Utilities.

(b) Third party purchase volumes with counterparties other than OMU increased in 2010 compared to 2009 primarily due to the termination of the OMU agreement. Third party purchase volumes with counterparties other than OMU decreased in 2009 compared to 2008 primarily due to availability of power for native load customers from the OMU agreement. See Note 13, Commitments and Contingencies, for further discussion of the OMU settlement.

Other Operation and Maintenance Expenses

The $26 million increase from 2009 to 2010 was primarily due to $22 million of increased other operation expenses and $4 million of increased maintenance expenses. The $45 million increase from 2008 to 2009 was primarily due to $30 million of increased other operation expenses and $15 million of increased maintenance expenses.

Other Operation Expenses:

The $22 million increase from 2009 to 2010 and $30 million increase from 2008 to 2009 were primarily due to:

	Increase (Decrease)	
	2010 vs. 2009	2009 vs. 2008
Administrative and general expense (a)	$ 9	$ 3
Transmission expense (b)	5	-
Bad debt expense (c)	4	(1)
Steam expense (d)	4	7
Generation expense	2	(2)
DSM program spending	-	9
Legal expenses (e)	-	(6)
Other power supply	(1)	-
Pension expense (f)	(2)	20
Other	1	-
	$ 22	$ 30

(a) Administrative and general expense increased in 2010 compared 2009 primarily due to higher labor expense and insurance expense, partially offset by lower IT expense related to the implementation of the Customer Care Solution system in 2009. Administrative and general expense increased in 2009 compared to 2008 primarily due to increased consulting fees for software training and increased labor and benefit costs.

(b) Transmission expense increased in 2010 compared to 2009 primarily due to a settlement agreement with a third party and the establishment of a regulatory asset approved by the Kentucky Commission for the EKPC settlement in 2009, net of twelve months of amortization expense recorded in 2010.

(c) Bad debt expense increased in 2010 compared to 2009 due to higher billed revenues, higher late payment charges and a higher net charge-off percentage.

(d) Steam expense increased in 2010 compared to 2009 primarily due to increased generation in 2010. Steam expense increased in 2009 compared to 2008 primarily due to the utilization of SCRs year-round.

(e) Legal expenses decreased in 2009 compared to 2008 primarily due to OMU expenses in 2008. See Note 13, Commitments and Contingencies, for further information regarding the OMU settlement.

(f) Pension expense decreased in 2010 compared to 2009 primarily due to favorable asset performance in 2009 and increased in 2009 compared to 2008 primarily due to unfavorable asset performance in 2008.

Other Maintenance Expenses:

The $4 million increase from 2009 to 2010 and $15 million increase from 2008 to 2009 were primarily due to:

	Increase (Decrease)	
	2010 vs. 2009	2009 vs. 2008
Generation expense (a)	$ 3	$ -
Steam expense (b)	2	7
Administrative and general expense	2	1
Transmission expense	-	2
Distribution expense (c)	(3)	5
	$ 4	$ 15

(a) Generation expense increased in 2010 compared to 2009 primarily due to the overhaul of Paddy's Run Unit 13.
(b) Steam expense increased in 2009 compared to 2008 due to increased scope of work for scheduled outages.
(c) Distribution expense decreased in 2010 compared to 2009 primarily due to higher storm cost in 2009, partially offset by higher tree trimming expense in 2010. Distribution expense increased in 2009 compared to 2008 primarily due to increased repairs, higher tree trimming expense and higher storm related expense.

Equity in Earnings of Unconsolidated Venture

The $2 million increase in equity in earnings of unconsolidated venture, from 2009 to 2010, was primarily due to higher earnings from EEI resulting from increased market prices for electric energy and the $29 million decrease from 2008 to 2009 was primarily due to lower earnings resulting from decreased market prices for electric energy.

Interest Expense

The $3 million increase from 2009 to 2010 and $3 million increase from 2008 to 2009 were primarily due to:

	Increase (Decrease)	
	2010 vs. 2009	2009 vs. 2008
Bond interest expense (a)	$ 8	$ (8)
Interest expense to affiliated companies (b)	(5)	11
	$ 3	$ 3

(a) Bond interest expense increased in 2010 compared to 2009 due to the issuance of first mortgage bonds in November 2010. Bond interest expense decreased in 2009 compared to 2008 due to lower interest rates on pollution control bonds. See Note 11, Long-Term Debt, for further information.
(b) Interest expense to affiliated companies decreased in 2010 compared to 2009 primarily due to notes payable to Fidelia being paid in full in November 2010, as a result of the PPL acquisition. Interest expense to affiliated companies increased in 2009 compared to 2008 primarily due to the

issuance of additional debt ($13 million), which was partially offset by lower interest rates on intercompany short-term borrowings.

Other Income (Expense) – Net

The $7 million decrease in other income (expense) – net from 2009 to 2010 and the $3 million decrease in other income (expense) – net from 2008 to 2009 were primarily due to the discontinuance of the allowance for funds used during construction on ECR projects as a result of the FERC rate case.

Income Tax Expense

See Note 10, Income Taxes, for a reconciliation of differences between the U.S. federal income tax expense at statutory rates and KU's income tax expense.

2011 Outlook

KU projects higher earnings in 2011 compared with 2010 as a net result of higher retail revenues and lower financing costs due to the issuance of first mortgage bonds in late 2010, partially offset by higher operation and maintenance expenses and depreciation. Retail revenues are expected to increase as a result of the 2010 Kentucky rate case and recoveries associated with its environmental investments. Operation and maintenance expenses and depreciation are expected to increase due to placing TC2 in service in January 2011. See Risk Factors for a discussion of the risk factors that may impact the 2011 outlook.

Financial Condition

Liquidity and Capital Resources

KU expects to continue to have adequate liquidity available through operating cash flows, cash and cash equivalents and its credit facilities. KU currently has no plans to access debt capital markets in 2011.

KU's cash flows from operations and access to cost-effective bank and capital markets are subject to risks and uncertainties including, but not limited to, the following:

- changes in market prices for electricity;
- potential ineffectiveness of the trading, marketing and risk management policy and programs used to mitigate KU's risk exposure to adverse electricity and fuel prices and interest rates;
- operational and credit risks associated with selling and marketing products in the wholesale power markets;
- unusual or extreme weather that may damage KU's transmission and distribution facilities or affect energy sales to customers;
- unavailability of generating units (due to unscheduled or longer than anticipated generation outages, weather and natural disasters) and the resulting loss of revenues and additional costs of replacement electricity;
- ability to recover and timeliness and adequacy of recovery of costs;
- costs of compliance with existing and new environmental laws;

- any adverse outcome of legal proceedings and investigations with respect to KU's current and past business activities;
- deterioration in the financial markets that could make obtaining new sources of bank and capital markets funding more difficult and more costly; and
- a downgrade in KU's credit ratings that could adversely affect its ability to access capital and increase the cost of credit facilities and any new debt.

See the Risk Factors section for further discussion of risks and uncertainties affecting KU's cash flows.

At December 31, KU had the following:

	Successor 2010	Predecessor 2009
Cash and cash equivalents	$ 3	$ 2
Current portion of long-term debt (a)	$ -	$ 228
Current portion of long-term debt to affiliated company (b)	-	33
Notes payable to affiliated companies (c)	10	45
	$ 10	$ 306

(a) 2009 amount represents Carroll County 2002 Series A and B, 2004 Series A, 2006 Series B and 2008 Series A; Muhlenberg County 2002 Series A; and Mercer County 2000 Series A and 2002 Series A pollution control bonds subject to tender for purchase at the option of the holder and to mandatory tender for purchase upon the occurrence of certain events. The Successor has classified these bonds as long-term because the Company has the intent and ability to utilize its $400 million credit facility which matures in December 2014, to fund any mandatory purchases. The Predecessor classified these bonds as the current portion of long-term debt due to the tender for purchase provisions. The Predecessor presentation and the Successor presentation are both appropriate under GAAP. See Note 1, Summary of Significant Accounting Policies, and Note 11, Long-Term Debt, for further information.

(b) 2009 amount represents debt owed to an E.ON affiliate, which was repaid in November 2010. See Note 11, Long-Term Debt, for further information.

(c) Amounts represent borrowings under KU's intercompany money pool agreement wherein LKE and/or LG&E make funds available to KU at market-based rates of up to $400 million. See Note 12, Notes Payable and Other Short-Term Obligations, for further information.

A condensed table of cash flows for the following periods in 2010, 2009 and 2008 is presented below. The Predecessor period, January 1, 2010 through October 31, 2010, and the Successor period, November 1, 2010 through December 31, 2010, were aggregated without further adjustment for purposes of comparison with the same periods in 2009 and 2008.

	Combined	Successor	Predecessor		
	Year Ended December 31, 2010	November 1, 2010 through December 31, 2010	January 1, 2010 through October 31, 2010	Year Ended December 31, 2009	Year Ended December 31, 2008
Net cash provided by (used in) operating activities	$ 372	$ 28	$ 344	$ 253	$ 292
Net cash provided by (used in) investing activities	(427)	(87)	(340)	(507)	(695)
Net cash provided by (used in) financing activities	56	58	(2)	254	405
Change in cash and cash equivalents	$ 1	$ (1)	$ 2	$ -	$ 2

Operating Activities

Net cash provided by operating activities increased by 47%, or $119 million, in 2010 compared with 2009, primarily as a result of increased earnings, increased collections from the ECR mechanism and lower storm expenses. These increases in cash flow were partially offset by higher interest payments due to an accelerated settlement with the previous owner and higher 2010 income tax payments due to higher taxable income and investment tax credit benefits received in 2009.

Net cash provided by operating activities decreased by 13%, or $39 million, in 2009 compared with 2008, primarily as a result of higher storm expenses, decreased earnings and unfavorable changes in working capital. These decreases in cash flow were partially offset by lower income tax payments due to lower taxable income and investment tax credit benefits received.

KU expects to achieve relatively stable cash flows from operations during the next three years although future cash flows may be significantly impacted by changes in economic conditions or new environmental and tax regulations.

Investing Activities

The primary use of cash in investing activities is capital expenditures. See "Forecasted Uses of Cash" for detail regarding projected capital expenditures for the years 2011 through 2013.

Net cash used in investing activities decreased by 16%, or $80 million, in 2010 compared with 2009, primarily as a result of a decrease of $89 million in capital expenditures, partially offset by a decrease of $9 million from restricted cash collections.

Net cash used in investing activities decreased by 27%, or $188 million, in 2009 compared with 2008, primarily as a result of a decrease of $180 million in capital expenditures and a increase of $8 million from restricted cash collections.

Financing Activities

Net cash provided by financing activities was $56 million in 2010 compared with $254 million in 2009. In spite of significant new debt issuances associated with the repayments to E.ON affiliates in connection with PPL's acquisition of the Company, cash provided by financing was less in 2010 due to lower increases in debt in 2010 and the payment of dividends in 2010; whereas, KU received equity contributions in 2009.

Net cash provided by financing activities was $254 million in 2009 compared with $405 million in 2008. The lower level of cash provided by financing in 2009 was the result of lower debt issuance to affiliated companies and lower levels of equity contributions received.

In the two months of 2010 following the acquisition, cash provided by financing activities of the Successor primarily consisted of the issuance of first mortgage bonds totaling $1,489 million after discounts and the issuance of intercompany notes totaling $1,331 million to a PPL subsidiary to repay debt due to an E.ON affiliate upon the closing of the sale. These amounts were offset by the repayment of $1,331 million to an E.ON affiliate upon the closing of the sale, the repayment of $1,331 million to a PPL affiliate upon the issuance of the first mortgage bonds, the repayment of $83 million of short-term borrowings due to an affiliated company and the payment of $17 million of debt issuance costs.

In 2010, cash used in financing activities by the Predecessor primarily consisted of the payment of $50 million of dividends to LKE mostly offset by increases in short-term borrowings due to an affiliated company totaling $48 million.

In 2009, cash provided by financing activities primarily consisted of the issuance of $150 million of intercompany notes to an E.ON affiliate, the receipt of capital contributions from LKE totaling $75 million and a $29 million increase in short-term borrowings due to an affiliated company.

In 2008, cash provided by financing activities primarily consisted of the issuance of $250 million of intercompany notes to an E.ON affiliate, the receipt of capital contributions from LKE totaling $145 million and a $7 million reduction in short-term borrowings due to an affiliated company. In addition, KU reacquired pollution control bonds totaling $80 million, reissued $63 million of that $80 million and issued $77 million of new pollution control bonds. Of the $77 million, $60 million was used to retire prior pollution control bonds, including the remaining $17 million which had been reacquired by the Company. This resulted in a cash receipt of $17 million to KU.

KU's debt financing activity in 2010 was:

	Issuances (a)	Retirements
Short-term borrowings from affiliated company – net change	$ -	$ (35)
Other borrowings from affiliated company	1,331	(1,331)
Borrowings from an E.ON affiliate	-	(1,331)
Issuance of bonds	1,489	-
Net change in debt financing	$ 2,820	$ (2,697)

(a) Issuances are net of pricing discounts, where applicable.

See Note 11, Long-Term Debt, for further information.

Working Capital Deficiency

As of December 31, 2009, KU had a working capital deficiency of $203 million, primarily due to the current portion of long-term debt to affiliated company totaling $33 million and $228 million of tax-exempt bonds which allow the investors to put the bonds back to the Company causing them to be classified as "Current portion of long-term debt." As of December 31, 2010, the Company no longer had a working capital deficiency because the current portion of long-term debt to affiliated company was paid off in conjunction with the PPL acquisition, and the $228 million of tax-exempt bonds were no longer classified as "Other current liabilities" by the Successor because the Company has the intent and ability to utilize its $400 million credit facility which expires in December 2014 to fund any mandatory purchases. See Note 11, Long-Term Debt, for further information.

Auction Rate Securities

Auctions for auction rate securities issued by KU continued to fail throughout 2010. See Note 11, Long-Term Debt, for further discussion.

Forecasted Sources of Cash

KU expects to continue to have adequate sources of cash available in the near term, including access to external financing, financing from affiliates and/or infusions of capital from LKE. Regulatory approvals are required for KU to incur additional debt. The FERC and the Virginia Commission authorize the issuance of short-term debt while the Kentucky Commission, Virginia Commission and the Tennessee Regulatory Authority authorize the issuance of long-term debt. In November 2009, 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 2011, allowing short-term borrowing of up to $400 million. Short-term funds are made available via the Company's participation in an intercompany money pool agreement wherein LKE and/or LG&E make funds available to KU at market-based rates (based on highly rated commercial paper issues) up to $400 million or via the $400 million Revolving Credit Agreement discussed below. KU currently believes this authorization and these facilities, together with the Company's credit facilities discussed below, provide the necessary flexibility to address any liquidity needs.

Credit Facilities

On November 1, 2010, KU entered into a $400 million unsecured Revolving Credit Agreement with a group of banks. Under this new credit facility, which expires on December 31, 2014, KU has the ability to make cash borrowings and to request the lenders to issue letters of credit. Borrowings will generally bear interest at LIBOR-based rates plus a spread, depending upon KU's senior unsecured long-term debt rating. The new credit facility contains financial covenants requiring KU's debt to total capitalization to not exceed 70% and other customary covenants. As of December 31, 2010, KU's debt to total capitalization was 41% as calculated pursuant to the credit agreement. Under certain conditions, KU may request that the facility's capacity be increased by up to $100 million. This new credit facility replaced an existing bilateral line of credit totaling $35 million that was terminated November 1, 2010. As of December 31, 2010, there was no outstanding balance under the new credit facility, but there were $198 million of letters of credit outstanding to support outstanding bonds totaling $195 million. KU will utilize unused credit facility and money pool balances to fund working capital needs as they arise. See Note 12, Notes Payable and Other Short-Term Obligations, for further information regarding the Company's credit facilities.

Contributions from LKE

LKE may make capital contributions to KU, which can be used for general business purposes.

Long-Term Debt

KU currently does not plan to issue any new long-term debt in 2011.

<u>Forecasted Uses of Cash</u>

In addition to expenditures required for normal operating activities, such as fuel for electric generation, power purchased, payroll and taxes; KU currently expects to incur future cash outflows for capital expenditures, various contractual obligations and the payment of dividends.

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 plans to fund capital expenditures through operating cash flows, the credit facility and, if needed, the issuance of long-term debt. KU expects its capital expenditures for the three year period ending December 31, 2013, to total approximately $1,406 million, consisting primarily of the following:

Construction of coal combustion residual storage structures	$ 346
Construction of environmental controls and capacity replacement	302
Construction of distribution and metering assets	260
Construction of generation assets	206
Construction of transmission assets	129
Recoverable environmental assets	99
Information technology projects	39
Other projects	25
	$ 1,406

The Company's capital program will focus primarily on compliance with existing or anticipated EPA environmental regulations, aging infrastructure and the need for increased storage capacity for coal combustion by-product materials over the next several years. This program may also 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 and other regulatory requirements. In particular, climate change initiatives, whether via legislative, regulatory or market channels, could restrict or disadvantage power generation from higher-carbon sources. Therefore, KU has included estimates regarding significant additional capital expenditures related to pending environmental regulations and legislation. These estimates are subject to final regulations and least cost analysis based on engineering studies. To the extent financial markets see climate change as a potential risk, KU may face reduced access to or increased costs in capital markets. Capital expenditures for KU associated with such actions are preliminarily estimated to be in the $1.5 to $1.7 billion range over the next ten years, although final costs may substantially vary.

See the Contractual Obligations table below and Note 13, Commitments and Contingencies, for further information concerning commitments.

Contractual Obligations

The following is provided to summarize contractual cash obligations for periods after December 31, 2010. KU anticipates cash from operations and external financing will be sufficient to fund future obligations. See the Statements of Capitalization.

	Payments Due by Period						
	2011	2012	2013	2014	2015	Thereafter	Total
Short-term debt (a)	$ 10	$ -	$ -	$ -	$ -	$ -	$ 10
Long-term debt (b)	-	-	-	-	250	1,601	1,851
Interest on long-term debt (c)	67	69	72	75	78	1,414	1,775
Operating leases (d)	8	7	5	5	3	1	29
Unconditional power purchase obligations (e)	9	10	10	10	10	114	163
Coal and natural gas purchase obligations (f)	439	200	144	93	91	14	981
Pension benefit plan obligations (g)	18	24	28	10	7	60	147
Postretirement benefit plan obligations (h)	5	6	6	6	6	33	62
Construction obligations (i)	113	3	-	-	-	-	116
Other obligations (j)	3	3	-	-	-	-	6
	$ 672	$ 322	$ 265	$ 199	$ 445	$ 3,237	$ 5,140

This table does not reflect contingent obligations. See Note 13, Commitments and Contingencies, for further information on contingent obligations.

(a) Represents borrowings due to affiliates within one year.
(b) Reflects principal maturities only based on legal maturity dates and includes the current portion of long-term debt.
(c) Assumes interest payments through maturity. The payments herein are subject to change as payments for debt that is or becomes variable-rate debt have been estimated.
(d) Represents future operating lease payments.
(e) Represents future minimum payments under OVEC power purchase agreements through March 13, 2026.
(f) Represents contracts to purchase coal, natural gas and natural gas transportation.

(g) Represents projected cash flows for funding the pension benefit plans as calculated by the actuary. For pension funding information see Note 9, Pension and Other Postretirement Benefit Plans.
(h) Represents projected cash flows for the postretirement benefit plan as calculated by the actuary. For postretirement funding information, see Note 9, Pension and Other Postretirement Benefit Plans.
(i) Represents construction commitments, including commitments for the Brown SCR and the Brown and Ghent landfill construction including associated material transport systems for coal combustion residual.
(j) Represents other contractual obligations including the SPP and TVA coordination agreements.

Pension and Postretirement Benefit Plans

See Application of Critical Accounting Policies and Estimates for discussion regarding discretionary contributions to the pension and postretirement benefit plans in 2011.

Dividends

Future dividends may be declared at the discretion of KU's Board of Directors, payable to its sole shareholder, LKE. As discussed in Note 12, Notes Payable and Other Short-Term Obligations, KU's dividend payments are limited under a covenant in its $400 million revolving line of credit facility. This covenant restricts the debt to total capital ratio to not more than 70%. KU is subject to Section 305(a) of the Federal Power Act, which makes it unlawful for a public utility to make or pay a dividend from any funds "properly included in capital account." The meaning of this limitation has never been clarified under the Federal Power Act. KU believes, however, that this statutory restriction, as applied to its circumstances, would not be construed or applied by the FERC to prohibit the payment from retained earnings of dividends that are not excessive and are for lawful and legitimate business purposes.

Purchase, Redemption or Remarketing of Debt Securities

KU will continue to evaluate purchasing, redeeming or remarketing outstanding debt securities and may decide to take action depending upon prevailing market conditions and available cash.

Credit Ratings

KU's credit ratings reflect the views of three national rating agencies. 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. In October 2010, one national rating agency revised downward the short-term credit rating of the pollution control bonds and the issuer rating of the Company as a result of the then pending acquisition by PPL. Another raised the long-term rating of the pollution control bonds as a result of the addition of the first mortgage bonds as collateral. In October 2010, a third national rating agency provided an initial rating of the Company's pollution control bonds and first mortgage bonds. See Note 11, Long-Term Debt, for a discussion of downgrade actions in 2009 and 2008 related to the pollution control bonds caused by a change in the rating of the entity insuring those bonds.

Ratings Triggers

KU has various derivative and non-derivative contracts, including contracts for the sale and purchase of electricity and fuel and commodity transportation, which contain provisions requiring KU to post additional collateral, or permit the counterparty to terminate the contract if KU's credit rating were to fall below investment grade. See Note 5, Derivative Financial Instruments, for a discussion of Credit Risk Related Contingent Features, including a discussion of the potential additional collateral that would have been required for derivative contracts in a net liability position at December 31, 2010. At December 31, 2010, if KU's credit ratings had been below investment grade, KU would have been required to prepay or post an additional $16 million of collateral to counterparties for both derivative and non-derivative commodity and commodity-related contracts used in its generation, marketing and trading operations.

Off-Balance Sheet Arrangements

KU has very limited off-balance sheet activity. See Note 13, Commitments and Contingencies, for further discussion.

Risk Management

Credit Risk

KU is exposed to potential losses as a result of nonperformance by counterparties of their contractual obligations. KU maintains credit policies and procedures to limit counterparty credit risk including evaluating credit ratings and financial information along with having certain counterparties post margin if the credit exposure exceeds certain thresholds. See Note 5, Derivative Financial Instruments, for information regarding risk management activities.

KU is exposed to potential losses as a result of nonpayment by customers. The Company maintains an allowance for doubtful accounts composed of accounts aged more than four months. Accounts are written off as management determines them uncollectible. See Application of Critical Accounting Policies and Estimates and Note 1, Summary of Significant Accounting Policies, for further discussion.

Certain of the Company's derivative instruments contain provisions that require it to provide immediate and on-going collateralization on derivative instruments in net liability positions based upon the Company's credit ratings from each of the major credit rating agencies. See Note 5, Derivative Financial Instruments, for information regarding exposure and the risk management activities.

Liquidity Risk

KU expects to continue to have access to adequate sources of liquidity through operating cash flows, cash and cash equivalents, credit facilities and/or infusion of capital from its parent. See Financial Condition - Liquidity and Capital Resources for an expanded discussion of KU's liquidity position and a discussion of its forecasted sources of cash.

Securities Price Risk

KU has securities price risk through its participation in defined benefit pension and postretirement benefit plans. Declines in the market price of debt and equity securities could impact contribution requirements. See Application of Critical Accounting Policies and Estimates - Defined Benefits for a discussion of the assumptions and sensitivities regarding the defined benefit pension and postretirement benefit plans assumptions.

Interest Rate and Commodity Price Risk

KU is subject to interest rate and commodity price risk related to on-going business operations. It currently manages commodity risks using derivative instruments, including swaps and forward contracts. The Company's policies allow for the interest rate risk to be managed through the use of fixed rate debt, floating rate debt and interest rate swaps. At December 31, 2010, no interest rate swaps were in effect for KU. At December 31, 2010, the Company's annual exposure to increased interest expense, based on a 10% increase in interest rates, was less than $1 million.

KU manages price risk by conducting energy trading activities through forward financial transactions. The following chart sets forth the net fair value of KU's commodity derivative contracts. See Note 5 Derivative Financial Instruments, for further information.

	Successor	Predecessor	
	December 31, 2010 (a)	October 31, 2010 (a)	December 31, 2009
Fair value of contracts outstanding at the beginning of the period	$ -	$ -	$ 1
Contracts realized or otherwise settled during the period	-	-	
Fair value of new contracts entered into during the period	-	-	-
Changes in fair value attributable to changes in valuation techniques	-	-	-
Other changes in fair value	-	-	(1)
Fair value of contracts outstanding at the end of the period	$ -	$ -	$ -

(a) 2010 activity is less than $1 million.

Related Party Transactions

KU and its Parent, LKE and subsidiaries of LKE engage in related party transactions. See Note 15, Related Party Transactions, for further information.

KU is not aware of any material ownership interest or operating responsibility by the executive officers of KU in outside partnerships, including leasing transactions with variable interest entities, or entities doing business with KU.

Acquisitions, Development and Divestitures

KU and LG&E have been constructing a new 760-Mw capacity base-load, coal-fired unit, TC2, which is jointly owned by KU (60.75%) and LG&E (14.25%), together with IMEA and IMPA (combined 25%). With limited exceptions the Company took care, custody and control of TC2 on January 22, 2011, and has dispatched the unit to meet customer demand since that date. KU and the contractor agreed to a further amendment of the construction agreement whereby the contractor will complete certain actions relating to identifying and completing any necessary modifications to allow operation of TC2 on all fuels in accordance with initial specifications prior to certain dates, and amending the provisions relating to liquidated damages. See Note 13, Commitments and Contingencies, for further information.

KU continuously re-examines development projects based on market conditions and other factors to determine whether to proceed, to cancel or to expand the projects.

Application of Critical Accounting Policies and Estimates

The financial statements of KU are prepared in compliance with GAAP. The application of these principles 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 also 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. KU's senior management has reviewed the significant and critical accounting policies with the relevant governing bodies of the Company and its parent, as applicable.

An accounting policy is deemed to be critical if it requires an accounting estimate to be made based on assumptions about matters that are highly uncertain at the time the estimate is made, if different estimates reasonably could have been used or if changes in the estimate that are reasonably possible could materially impact the financial statements. Management believes the following critical accounting policies reflect the significant estimates and assumptions used in the preparation of the Financial Statements.

Price Risk Management

See Financial Condition - Risk Management.

Regulatory Mechanisms

KU is a cost-based rate-regulated utility. As a result, the financial statements reflect the effects of regulatory actions. Regulatory assets are recognized for the effect of transactions or events where future recovery is probable in regulated customer rates. The effect of such accounting is to defer certain or qualifying costs that would otherwise be charged to expense. Likewise, regulatory liabilities are recognized for obligations expected to be returned through future regulated customer rates. The effect of such transactions or events would otherwise be reflected as income. In certain cases, regulatory liabilities are recorded based on the understanding with the regulator that current rates are being set to recover costs that are expected to be incurred in the future. The regulated entity is accountable for any amounts charged pursuant to such rates and not yet expended for the intended purpose. The accounting for regulatory assets and liabilities is based on specific ratemaking decisions or precedent for each transaction or event as prescribed by the FERC, the Kentucky Commission, the Virginia Commission or the Tennessee Regulatory Authority. See Note 3, Rates and Regulatory Matters, for additional detail regarding regulatory assets and liabilities.

Defined Benefits

KU employees benefit from both funded and unfunded retirement benefit plans. See Note 1, Summary of Significant Accounting Policies, for information about policy changes between the Predecessor and Successor and the accounting for defined benefits including KU's method of amortizing gains and losses. KU makes various assumptions in arriving at pension and other postretirement benefit costs and obligations. The major assumptions include:

- KU's selection of discount rates is based on the Mercer Pension Discount Yield Curve (Predecessor) and the Towers Watson Yield Curve (Successor).
- KU's selection of rate of salary growth is based on historical data that includes employees' periodic pay increases and promotions, which are used to project employees' pension benefits at retirement.
- KU determines the expected long-term return on plan assets based on the current level of expected return 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 is then weighted based on the current asset allocation.
- KU's management projects health care cost trends based on past health care costs, the near-term outlook and an assessment of likely long-term trends.

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 return on investments within the plans was approximately 12% for the year ended December 31, 2010. The benefit plan assets and obligations are re-measured annually using a December 31 measurement date. Due to the PPL acquisition, the benefit plan assets and obligations were also re-measured at October 31, 2010. The Company's 2010 pension cost was approximately $3 million less than 2009. The Company anticipates its 2011 pension cost will be approximately $3 million less than the 2010 expense. The amount of future funding will depend upon the actual return on plan assets, the discount rate and other factors, but the Company funds its pension obligations in a manner consistent with the Pension Protection Act of 2006. The Company made discretionary contributions to its pension plan of $13 million in 2010 and 2009, respectively. In January 2011, KU contributed $43 million to its pension plan. See Note 18, Subsequent Events, for further information.

See Note 9, Pension and Other Postretirement Benefit Plans, for further information on defined benefits including sensitivity analysis expressing potential changes in expected returns that would result from hypothetical changes to assumptions and estimates, expected rate of return assumptions and health care trends.

Asset Impairment

KU performs a quarterly review to determine if an impairment analysis is required for long-lived assets that are subject to depreciation or amortization. This review identifies changes in circumstances indicating that a long-lived asset's carrying value may not be recoverable. An impairment analysis will be performed if warranted based on the review. For these long-lived assets, such events or changes in circumstances which may indicate an impairment analysis is required include:

- a significant decrease in the market price of an asset;
- a significant adverse change in the manner in which an asset is being used or in its physical condition;
- a significant adverse change in legal factors or in the business climate;
- an accumulation of costs significantly in excess of the amount originally expected for the acquisition or construction of an asset;
- a current-period operating or cash flow loss combined with a history of losses or a forecast that demonstrates continuing losses;
- a current expectation that, more likely than not, an asset will be sold or otherwise disposed of before the end of its previously estimated useful life; and
- a significant change in the physical condition of an asset.

For a long-lived asset, impairment is recognized when the carrying amount of the asset is not recoverable and exceeds its fair value. The carrying amount is not recoverable if it exceeds the sum of the undiscounted cash flows expected to result from the use and eventual disposition of the asset. If the asset is impaired, an impairment loss is recorded to adjust the asset's carrying value to its estimated fair value. Management must make significant judgments to estimate future cash flows including the useful lives of long-lived assets, the fair value of the assets and management's intent to use the assets. KU did not recognize an impairment of any long-lived asset in 2010.

Effective with PPL's acquisition of LKE on November 1, 2010, KU recorded $607 million of goodwill. At December 31, 2010, KU's goodwill remained unchanged. GAAP requires goodwill to be tested for impairment on an annual basis or more frequently if events or circumstances indicate that assets may be impaired. KU performs its annual goodwill impairment test in the fourth quarter. See Note 7, Goodwill and Intangible Assets, for further discussion.

Goodwill is tested for impairment using a two-step approach. In step 1, the Company identifies a potential impairment by comparing the estimated fair value of the Company (the goodwill reporting unit) to its carrying value, including goodwill, on the measurement date. If the estimated fair value exceeds its carrying amount, goodwill is not considered impaired. If the carrying amount exceeds the estimated fair value, the second step is performed to measure the amount of impairment loss, if any.

The second step requires a calculation of the implied fair value of goodwill. The implied fair value of goodwill is determined in the same manner as the amount of goodwill in a business combination. That is, the estimated fair value is allocated to all of KU's assets and liabilities as if KU had been acquired in a business combination and the estimated fair value of KU was the price paid. The excess of the estimated fair value of KU over the amounts assigned to its assets and liabilities is the implied fair value of goodwill. The implied fair value of goodwill is then compared with the carrying amount of that goodwill. If the carrying amount exceeds the implied fair value, an impairment loss is recognized in an amount equal to that excess. The loss recognized cannot exceed the carrying amount of the reporting unit's goodwill.

Determining the fair value of KU is judgmental in nature and involves the use of significant estimates and assumptions. These estimates and assumptions can include revenue growth rates and operating margins used to calculate projected future cash flows, risk adjusted discount rates and future economic and market conditions.

KU tested goodwill for impairment in the fourth quarter of 2010 and no impairment was recognized. See Note 7, Goodwill and Intangible Assets, for further discussion.

Loss Accruals

KU accrues losses for the estimated impacts of various conditions, situations or circumstances involving uncertain or contingent future outcomes. For loss contingencies, the loss must be accrued if (1) information is available that indicates it is probable that a loss has been incurred, given the likelihood of the uncertain future events and (2) the amount of the loss can be reasonably estimated. Accounting guidance defines "probable" as cases in which "the future event or events are likely to occur." KU does not record the accrual of contingencies that might result in gains, unless recovery is assured. KU continuously assesses potential loss contingencies for environmental remediation, litigation claims, regulatory penalties and other events.

The accounting aspects of estimated loss accruals include (1) the initial identification and recording of the loss, (2) the determination of triggering events for reducing a recorded loss accrual and (3) the ongoing assessment as to whether a recorded loss accrual is sufficient. All three of these aspects require significant judgment by KU's management. KU uses its internal expertise and outside experts (such as lawyers and engineers), as necessary, to help estimate the probability that a loss has been incurred and the amount or range of the loss.

KU has identified certain other events that could give rise to a loss, but that do not meet the conditions for accrual. Such events are disclosed, but not recorded, when it is reasonably possible that a loss has been incurred. Accounting guidance defines "reasonably possible" as cases in which "the future event or events occurring is more than remote, but less than likely to occur." See Note 13, Commitments and Contingencies, for disclosure of other potential loss contingencies that have not met the criteria for accrual.

When an estimated loss is accrued, KU identifies, where applicable, the triggering events for subsequently adjusting the loss accrual. The triggering events generally occur when the contingency has been resolved and the actual loss is incurred, or when the risk of loss has diminished or been eliminated. The following are some of the triggering events that provide for the adjustment of certain recorded loss accruals:

- Allowances for uncollectible accounts are reduced when accounts are written off after prescribed collection procedures have been exhausted, a better estimate of the allowance is determined or underlying amounts are ultimately collected.
- Environmental and other litigation contingencies are reduced when the contingency is resolved, KU makes actual payments, a better estimate of the loss is determined or the loss is no longer considered probable.

KU reviews its loss accruals on a regular basis to assure that the recorded potential loss exposures are appropriate. This involves ongoing communication and analyses with internal and external legal counsel, engineers, operation management and other parties. This review may result in the increase or decrease of the loss accrual.

Asset Retirement Obligations

KU is required to recognize a liability for legal obligations associated with the retirement of long-lived assets. The initial obligation is measured at its estimated fair value. An equivalent amount is recorded as an increase in the value of the capitalized asset and allocated to expense over the useful life of the asset. Until the obligation is settled, the liability is increased, through the recognition of accretion expense in the Statements of Income, for changes in the obligation due to the passage of time. An offsetting regulatory asset is recognized to reverse the depreciation and accretion expense related to the ARO such that there is no income statement impact. The regulatory asset is relieved when the ARO has been settled. An ARO must be recognized when incurred if the fair value of the ARO can be reasonably estimated.

In determining AROs, management must make significant judgments and estimates to calculate fair value. Fair value is developed using an expected present value technique based on assumptions of market participants that considers estimated retirement costs in current period dollars that are inflated to the anticipated retirement date and then discounted back to the date the ARO was incurred. Changes in assumptions and estimates included within the calculations of the fair value of AROs could result in significantly different results than those identified and recorded in the financial statements. Estimated ARO costs and settlement dates, which affect the carrying value of various AROs and the related assets, are reviewed periodically to ensure that any material changes are incorporated into the estimate of the obligations. Any change to the capitalized asset is amortized over the remaining life of the associated long-lived asset. See Note 4, Asset Retirement Obligations, for further information on AROs.

At December 31, 2010, KU had AROs totaling $54 million recorded on the Balance Sheets. Of the total amount, $35 million, or 65%, relates to KU's ash ponds and landfills. The most significant assumptions surrounding AROs are the forecasted retirement costs, the discount rates and the inflation rates. A variance in the forecasted retirement costs, the discount rates or the inflation rates could have a significant impact on the ARO liabilities.

The following chart reflects the sensitivities related to KU's ARO liabilities for ash ponds and landfills as of December 31, 2010:

	Change in Assumption	Impact on ARO Liability
Retirement cost	10%/(10)%	$4/$(4)
Discount rate	0.25%/(0.25)%	$(2)/$1
Inflation rate	0.25%/(0.25)%	$2/$(2)

Income Tax Uncertainties

Significant management judgment is required in developing KU's provision for income taxes primarily due to the uncertainty related to tax positions taken or expected to be taken in tax returns and the determination of deferred tax assets, liabilities and valuation allowances.

Significant management judgment is required to determine the amount of benefit recognized related to an uncertain tax position. KU evaluates its tax positions following a two-step process. The first step requires an entity to determine whether, based on the technical merits supporting a particular tax position, it is more likely than not (greater than a 50% chance) that the tax position will be sustained. This determination assumes that the relevant taxing authority will examine the tax position and is aware of all the relevant facts surrounding the tax position. The second step requires an entity to recognize in the financial statements the benefit of a tax position that meets the more-likely-than-not recognition criterion. The benefit recognized is measured at the largest amount of benefit that has a likelihood of realization, upon settlement, that exceeds 50%. KU's management considers a number of factors in assessing the benefit to be recognized, including negotiation of a settlement.

On a quarterly basis, KU reassesses its uncertain tax positions by considering information known at the reporting date. Based on management's assessment of new information, KU may subsequently recognize a tax benefit for a previously unrecognized tax position, de-recognize a previously recognized tax position or re-measure the benefit of a previously recognized tax position. The amounts ultimately paid upon resolution of issues raised by taxing authorities may differ materially from the amounts accrued and may materially impact KU financial statements in the future.

The balance sheet classification of unrecognized tax benefits and the need for valuation allowances to reduce deferred tax assets also require significant management judgment. KU classifies unrecognized tax benefits as current, to the extent management expects to settle an uncertain tax position, by payment or receipt of cash, within one year of the reporting date. Valuation allowances are initially recorded and reevaluated each reporting period by assessing the likelihood of the ultimate realization of a deferred tax asset. Management considers a number of factors in assessing the realization of a deferred tax asset, including the reversal of temporary differences, future taxable income and ongoing prudent and feasible tax planning strategies. Any tax planning strategy utilized in this assessment must meet the recognition and measurement criteria utilized by KU to account for an uncertain tax position. See Note 10, Income Taxes, for the required disclosures.

At December 31, 2010, KU's existing reserve exposure to either increases or decreases in unrecognized tax benefits during the next 12 months is less than $1 million. This change could result from subsequent recognition, de-recognition and/or changes in the measurement of uncertain tax positions. The events that could cause these changes are direct settlements with taxing authorities, litigation, legal or administrative guidance by relevant taxing authorities and the lapse of an applicable statute of limitations.

Purchase Price Allocation

On November 1, 2010, PPL completed the acquisition of KU's parent. In accordance with accounting guidance on business combinations, the identifiable assets acquired and the liabilities assumed were measured at fair value at the acquisition date. Fair value is defined as the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants. The excess of the purchase price over the estimated fair value of the identifiable net assets is recorded as goodwill.

The determination and allocation of fair value to the identifiable assets acquired and liabilities assumed was based on various assumptions and valuation methodologies requiring considerable management judgment, including estimates based on key assumptions of the acquisition and historical and current market data. The most significant variables in these valuations were the discount rates, the number of years on which to base cash flow projections, as well as the assumptions and estimates used to determine cash inflows and outflows. Although the assumptions applied were reasonable based on information available at the date of acquisition, actual results may differ from the forecasted amounts and the difference could be material.

For purposes of measuring the fair value of the majority of property, plant and equipment and regulatory assets acquired and regulatory liabilities assumed, KU determined that fair value was equal to net book value at the acquisition date because KU's operations are conducted in a regulated environment and the regulatory commissions allow for earning a rate of return on the book value of a majority of the regulated asset bases at rates determined to be fair and reasonable. As there is no current prospect for deregulation in KU's operating area, it is expected that these operations will remain in a regulated environment for the foreseeable future, therefore management has concluded that the use of these assets in the regulatory environment represents their highest and best use and a market participant would measure the fair value of these assets using the regulatory rate of return as the discount rate, thus resulting in fair value equal to book value.

The fair value of intangible assets and liabilities (e.g. contracts that have favorable or unfavorable terms relative to market), including coal contracts and power purchase agreements, as well as emission allowances, have been reflected on the Balance Sheets with offsetting regulatory assets or liabilities. Prior to the acquisition, KU recovered the cost of the coal contracts, power purchases and emission allowances and this rate treatment will continue after the acquisition. As a result, management believes the regulatory assets and liabilities created to offset the fair value adjustments meet the recognition criteria established by existing accounting guidance and eliminate any ratemaking impact of the fair value adjustments. KU's customer rates will continue to reflect these items (e.g. coal, purchased power, emission allowances) at their original contracted prices.

KU also considered whether a separate fair value should be assigned to KU's rights to operate within its various electric service areas but concluded that these rights only provided the opportunity to earn a regulated return and barriers to market entry, which in management's judgment is not considered a separately identifiable intangible asset under applicable accounting guidance; rather, it is considered going-concern value, or goodwill.

See Note 2, Acquisition by PPL and Note 7, Goodwill and Intangible Assets, for further information.

<u>New Accounting Guidance</u>

Recent accounting pronouncements affecting KU are detailed in Note 1, Summary of Significant Accounting Policies.

Other Information

PPL's Audit Committee has approved the audit fees and audit-related services. The audit-related services include services in connection with regulatory filings, reviews of offering documents and registration statements and internal control reviews.

Management's Report of Internal Controls Over Financial Reporting

Through December 31, 2010, the Company was 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 its internal control over financial reporting pursuant to Section 404 of the Act. However, management is responsible for establishing and maintaining adequate internal control over financial reporting. Internal control over financial reporting is a process affected by those charged with governance, management, and other personnel, designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with GAAP. 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 GAAP 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.

Management has assessed the effectiveness of the Company's internal control over financial reporting as of December 31, 2010, using the criteria set forth by the Committee of Sponsoring Organizations of the Treadway Commission in *Internal Control – Integrated Framework*. Management has concluded that, as of December 31, 2010, the Company's internal control over financial reporting was effective based on those criteria.

The effectiveness of the Company's internal control over financial reporting as of December 31, 2010, has been audited by PricewaterhouseCoopers LLP, an independent accounting firm, as stated in its report which is included herein.

Kentucky Utilities Company
Statements of Retained Earnings
(millions)

	Successor	Predecessor		
	November 1, 2010 through December 31, 2010	January 1, 2010 through October 31, 2010	Year Ended December 31, 2009	Year Ended December 31, 2008
Balance at beginning of period	$ 1,418	$ 1,328	$ 1,195	$ 1,037
Effect of PPL acquisition	(1,418)	-	-	-
Balance at November 1, 2010	-	1,328	1,195	1,037
Net income	35	140	133	158
Cash dividends declared (Note 15)	-	(50)	-	-
Balance at end of period	$ 35	$ 1,418	$ 1,328	$ 1,195

The accompanying notes are an integral part of these financial statements.

Kentucky Utilities Company
Statements of Comprehensive Income
(millions)

	Successor	Predecessor		
	November 1, 2010 through December 31, 2010	January 1, 2010 through October 31, 2010	Year Ended December 31, 2009	Year Ended December 31, 2008
Net income	$ 35	$ 140	$ 133	$ 158
Equity investee's other comprehensive loss, net of tax expense of $0, $1, $0 and $0, respectively (Note 1)	-	(2)	-	-
Comprehensive income	$ 35	$ 138	$ 133	$ 158

The accompanying notes are an integral part of these financial statements.

Kentucky Utilities Company
Balance Sheets
(millions)

Assets	Successor December 31, 2010	Predecessor December 31, 2009
Current assets:		
Cash and cash equivalents	$ 3	$ 2
Accounts receivable (less allowance for doubtful accounts: 2010, $6; 2009, $3):		
Customer	90	79
Affiliated companies	12	9
Other	20	18
Unbilled revenues	89	76
Fuel, materials and supplies:		
Fuel (predominantly coal)	95	98
Other materials and supplies	41	39
Other intangible assets	22	-
Regulatory assets (Note 3)	9	32
Prepayments and other current assets	15	13
Total current assets	396	366
Investment in unconsolidated venture (Note 1)	30	12
Property, plant and equipment:		
Regulated utility plant – electric	3,630	4,892
Accumulated depreciation	(14)	(1,838)
Net regulated utility plant	3,616	3,054
Construction work in progress	955	1,257
Property, plant and equipment – net	4,571	4,311
Deferred debits and other assets:		
Regulatory assets (Notes 3 and 9):		
Pension benefits	117	105
Other regulatory assets	105	117
Goodwill (Notes 2 and 7)	607	-
Other intangibles assets (Notes 2 and 7)	175	-
Cash surrender value of key man life insurance	39	38
Other assets	19	7
Total deferred debits and other assets	1,062	267
Total assets	$ 6,059	$ 4,956

The accompanying notes are an integral part of these financial statements.

Kentucky Utilities Company
Balance Sheets (continued)
(millions)

Liabilities and Equity	Successor December 31, 2010	Predecessor December 31, 2009
Current liabilities:		
Current portion of long-term debt (Note 11)	$ -	$ 228
Current portion of long-term debt to affiliated company (Notes 11 and 15)	-	33
Notes payable to affiliated companies (Notes 12 and 15)	10	45
Accounts payable	67	107
Accounts payable to affiliated companies (Note 15)	45	88
Accrued taxes	25	14
Customer deposits	23	22
Regulatory liabilities (Note 3)	41	4
Accrued interest	8	1
Employee accruals	15	13
Other current liabilities	18	14
Total current liabilities	252	569
Long-term debt:		
Long-term bonds (Note 11)	1,841	123
Long-term debt to affiliated company (Notes 11 and 15)	-	1,298
Total long-term debt	1,841	1,421
Deferred credits and other liabilities:		
Deferred income taxes (Note 10)	376	336
Accumulated provision for pensions (Note 9)	113	160
Investment tax credits (Note 10)	104	104
Asset retirement obligations (Notes 3 and 4)	54	34
Regulatory liabilities (Note 3):		
Accumulated cost of removal of utility plant	348	335
Other regulatory liabilities	186	25
Other liabilities	94	20
Total deferred credits and other liabilities	$ 1,275	$ 1,014

The accompanying notes are an integral part of these financial statements.

Kentucky Utilities Company
Balance Sheets (continued)
(millions)

	Successor December 31, 2010	Predecessor December 31, 2009
Equity:		
Common stock, without par value – authorized 80,000,000 shares, outstanding 37,817,878 shares	$ 308	$ 308
Additional paid-in capital	2,348	316
Retained earnings:		
Retained earnings	35	1,318
Undistributed earnings from unconsolidated venture	-	10
Total equity	2,691	1,952
Total liabilities and equity	$ 6,059	$ 4,956

The accompanying notes are an integral part of these financial statements.

Kentucky Utilities Company
Statements of Cash Flows
(millions)

	Successor	Predecessor		
	November 1, 2010 through December 31, 2010	January 1, 2010 through October 31, 2010	Year Ended December 31, 2009	Year Ended December 31, 2008
Cash flows from operating activities:				
Net income	$ 35	$ 140	$ 133	$ 158
Adjustments to reconcile net income to net cash provided by (used in) operating activities:				
Depreciation and amortization	26	119	133	136
Deferred income taxes – net	4	23	50	(13)
Investment tax credits (Note 10)	-	-	24	25
Provision for pension and postretirement benefits	5	13	26	10
Other – net	2	(3)	-	1
Change in current assets and liabilities:				
Accounts receivable	(15)	13	11	13
Unbilled revenues	(32)	19	(15)	(1)
Fuel, materials and supplies	5	(6)	(28)	(33)
Regulatory assets	(2)	19	-	-
Other current assets	9	(9)	(3)	(1)
Accounts payable	9	(17)	(32)	2
Accounts payable to affiliated companies	(41)	46	29	7
Accrued taxes	15	(5)	6	8
Regulatory liabilities	12	3	-	-
Other current liabilities	(2)	2	2	(3)
Pension and postretirement funding (Note 9)	(2)	(18)	(20)	(5)
Storm restoration regulatory asset (Note 3)	-	-	(57)	(2)
Other regulatory assets	1	8	-	-
Other regulatory liabilities	-	(10)	-	-
Other – net	(1)	7	(6)	(10)
Net cash provided by (used in) operating activities	28	344	253	292
Cash flows from investing activities:				
Construction expenditures	(87)	(292)	(516)	(686)
Purchases of assets from affiliate	-	(48)	-	(10)
Change in restricted cash	-	-	9	1
Net cash provided by (used in) investing activities	$ (87)	$ (340)	$ (507)	$ (695)

The accompanying notes are an integral part of these financial statements.

Kentucky Utilities Company
Statements of Cash Flows (continued)
(millions)

	Successor	Predecessor		
	November 1, 2010 through December 31, 2010,	January 1, 2010 through October 31, 2010	Year Ended December 31, 2009	Year Ended December 31, 2008
Cash flows from financing activities:				
Issuance of bonds (Note 11)	$ 1,489	$ -	$ -	$ 77
Short-term borrowings from affiliated company – net (Note 12)	(83)	48	29	(7)
Other borrowings from affiliated companies (Note 11)	1,331	-	150	250
Repayments on other borrowings from affiliated companies (Note 11)	(1,331)	-	-	-
Repayments to E.ON affiliate (Note 11)	(1,331)	-	-	-
Debt issuance costs	(17)	-	-	-
Retirement of pollution control bonds	-	-	-	(60)
Acquisition of outstanding bonds	-	-	-	(80)
Reissuance of reacquired bonds	-	-	-	63
Retirement of reacquired bonds	-	-	-	17
Payment of dividends	-	(50)	-	-
Capital contribution (Note 15)	-	-	75	145
Net cash provided by (used in) financing activities	58	(2)	254	405
Change in cash and cash equivalents	(1)	2	-	2
Cash and cash equivalents at beginning of period	4	2	2	-
Cash and cash equivalents at end of period	$ 3	$ 4	$ 2	$ 2
Supplemental disclosures of cash flow information:				
Cash paid (received) during the year for:				
Interest – net of amount capitalized	$ 22	$ 62	$ 70	$ 66
Income taxes – net	(12)	74	(9)	46

The accompanying notes are an integral part of these financial statements.

Kentucky Utilities Company
Statements of Capitalization
(millions)

	Successor December 31, 2010	Predecessor December 31, 2009
Long-term debt (Note 11):		
Pollution control series:		
Mercer Co. 2000 Series A, due May 1, 2023, variable %	$ 13	$ 13
Carroll Co. 2007 Series A, due February 1, 2026, 5.75%	18	18
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. 2008 Series A, due February 1, 2032, variable %	78	78
Carroll Co. 2002 Series C, due October 1, 2032, variable %	96	96
Carroll Co. 2006 Series B, due October 1, 2034, variable %	54	54
Trimble Co. 2007 Series A, due March 1, 2037, 6.0%	9	9
Carroll Co. 2004 Series A, due October 1, 2034, variable %	50	50
Total pollution control series	351	351
First mortgage bonds:		
First mortgage bond 2015 Series, due November 1, 2015, 1.625%	250	-
First mortgage bond 2020 Series, due November 1, 2020, 3.25%	500	-
First mortgage bond 2040 Series, due November 1, 2040, 5.125%	750	-
Total first mortgage bonds	$ 1,500	$ -

The accompanying notes are an integral part of these financial statements.

Kentucky Utilities Company
Statements of Capitalization (continued)
(millions)

	Successor December 31, 2010	Predecessor December 31, 2009
Long-term debt to affiliated company:		
Due November 24, 2010, 4.24%, unsecured	$ -	$ 33
Due January 16, 2012, 4.39%, unsecured	-	50
Due April 30, 2013, 4.55%, unsecured	-	100
Due August 15, 2013, 5.31%, unsecured	-	75
Due December 19, 2014, 5.45%, unsecured	-	100
Due July 8, 2015, 4.735%, unsecured	-	50
Due December 21, 2015, 5.36%, unsecured	-	75
Due October 25, 2016, 5.675%, unsecured	-	50
Due April 24, 2017, 5.28%, unsecured	-	50
Due June 20, 2017, 5.98%, unsecured	-	50
Due July 25, 2018, 6.16%, unsecured	-	50
Due August 27, 2018, 5.645%, unsecured	-	50
Due December 17, 2018, 7.035%, unsecured	-	75
Due July 29, 2019, 4.81%, unsecured	-	50
Due October 25, 2019, 5.71%, unsecured	-	70
Due November 25, 2019, 4.445%, unsecured	-	50
Due February 7, 2022, 5.69%, unsecured	-	53
Due May 22, 2023, 5.85%, unsecured	-	75
Due September 14, 2028, 5.96%, unsecured	-	100
Due June 23, 2036, 6.33%, unsecured	-	50
Due March 30, 2037, 5.86%, unsecured	-	75
Total long-term debt to affiliated company	-	1,331
Total long-term debt outstanding	1,851	1,682
Purchase accounting adjustments and discounts	(10)	-
Less current portion of long-term debt	-	261
Long-term debt	$ 1,841	$ 1,421

The accompanying notes are an integral part of these financial statements.

Kentucky Utilities Company
Statements of Capitalization (continued)
(millions)

	Successor December 31, 2010	Predecessor December 31, 2009
Common equity:		
Common stock, without par value – authorized 80,000,000 shares, outstanding 37,817,878 shares	$ 308	$ 308
Additional paid-in-capital	2,348	316
Retained earnings:		
Retained earnings	35	1,318
Undistributed subsidiary earnings	-	10
Total retained earnings	35	1,328
Total common equity	2,691	1,952
Total capitalization	$ 4,532	$ 3,373

The accompanying notes are an integral part of these financial statements.

Note 1 - Summary of Significant Accounting Policies

General

Terms and abbreviations are explained in the index of abbreviations. Dollars are in millions unless otherwise noted.

Business

KU, incorporated in Kentucky in 1912 and in Virginia in 1991, is a regulated utility engaged in the generation, transmission, distribution and sale of electric energy in Kentucky, Virginia and Tennessee. KU provides electric service to approximately 514,000 customers in 77 counties in central, southeastern and western Kentucky, to approximately 30,000 customers in five counties in southwestern Virginia and less than ten customers in Tennessee. KU's service area covers approximately 6,600 noncontiguous square miles. Approximately 98% of the electricity generated by KU is produced by its coal-fired electric generating stations. The remainder is generated by natural gas and oil fueled CTs and a hydroelectric power plant. In Virginia, KU operates under the name Old Dominion Power Company. KU also sells wholesale electric energy to 12 municipalities.

On November 1, 2010, KU became an indirect wholly owned subsidiary of PPL, when PPL acquired all of the outstanding limited liability company interests in the Company's direct parent, LKE, from E.ON US Investments Corp. LKE, a Kentucky limited liability company, also owns the affiliate, LG&E, a regulated utility engaged in the generation, transmission, distribution and sale of electric energy and distribution and sale of natural gas in Kentucky. Following the acquisition, the Company's business has not changed. KU and LG&E are continuing as subsidiaries of LKE, which is now an intermediary holding company in the PPL group of companies.

Headquartered in Allentown, Pennsylvania, PPL is an energy and utility holding company that was incorporated in 1994. Through its subsidiaries, PPL owns or controls about 19,000 megawatts of generating capacity in the U.S., sells energy in key U.S. markets and delivers electricity and natural gas to about 5.3 million customers in the U.S. and the U.K.

Basis of Accounting

KU's basis of accounting incorporates the business combinations guidance of the FASB ASC as of the date of the acquisition, which requires the recognition and measurement of identifiable assets acquired and liabilities assumed at fair value as of the acquisition date. KU's financial statements and accompanying footnotes have been segregated to present pre-acquisition activity as the Predecessor and post-acquisition activity as the Successor. Predecessor covers the time period prior to November 1, 2010. Successor covers the time period after October 31, 2010. Certain accounting and presentation methods were changed to acceptable alternatives to conform to PPL accounting policies, which are discussed below, and the cost basis of certain assets and liabilities were changed as of November 1, 2010, as a result of the application of push-down accounting. Consequently, the financial position, results of operations and cash flows for the Predecessor period are not comparable to the Successor period.

Despite the separate presentation, the core operations of the Company have not changed. See Note 2, Acquisition by PPL, for information regarding the acquisition and the purchase accounting adjustments.

Changes in Classification

Certain reclassification entries have been made to the Predecessor's previous years' financial statements to conform to the 2010 presentation with no impact on net assets, liabilities and capitalization or previously reported net income and cash flows. These reclassifications mainly consist of those necessary to identify amounts for prior periods that are separately disclosed in the financial statements.

Regulatory Accounting

KU is a cost-based rate-regulated utility. As a result, the financial statements reflect the effects of regulatory actions. Regulatory assets are recognized for the effect of transactions or events where future recovery is probable in regulated customer rates. The effect of such accounting is to defer certain or qualifying costs that would otherwise be charged to expense. Likewise, regulatory liabilities may be recognized for obligations expected to be returned through future regulated customer rates. The effect of such transactions or events would otherwise be reflected as income, or, in certain cases, regulatory liabilities are recorded based on the understanding with the regulator that current rates are being set to recover costs that are expected to be incurred in the future. The regulated entity is accountable for any amounts charged pursuant to such rates and not yet expended for the intended purpose. Offsetting regulatory assets or liabilities for fair value purchase accounting adjustments have also been recorded to eliminate any ratemaking impact of the fair value adjustments. The accounting for regulatory assets and liabilities is based on specific ratemaking decisions or precedent for each transaction or event as prescribed by the FERC, Kentucky Commission, Virginia Commission or the Tennessee Regulatory Authority. See Note 3, Rates and Regulatory Matters, for additional detail regarding regulatory assets and liabilities.

Management's Use of Estimates

The preparation of financial statements in conformity with GAAP requires management to make estimates and assumptions that affect the reported assets and liabilities, the disclosure of contingent liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. Actual results could differ from those estimates.

Derivative Financial Instruments

KU enters into energy trading contracts to manage price risk and to maximize the value of power sales from the physical assets it owns. The energy trading contracts are non-hedging derivatives and the change in value is recognized in earnings on a mark-to-market basis. The Predecessor and Successor presentation are both appropriate under GAAP. The Predecessor and Successor determine the classification of energy trading contracts based on the settlement date of the individual contracts. Energy trading contracts classified as current are recognized in "Prepayments and other current assets" or "Other current liabilities" on the Balance Sheets. Energy trading contracts classified as non-current are recognized in "Other assets" or "Other liabilities" on the Balance Sheets. Cash inflows and outflows related to derivative instruments are included as a component of operating activity on the Statements of Cash Flows, due to the underlying nature of the hedged items.

The Company does not net collateral against derivative instruments.

See Note 5, Derivative Financial Instruments, and Note 6, Fair Value Measurements, for further information on derivative instruments.

Revenue and Accounts Receivable

The operating revenues line item in the Statements of Income contains revenues from the following:

	Successor	Predecessor		
	November 1, 2010 through December 31, 2010	January 1, 2010 through October 31, 2010	Year Ended December 31, 2009	Year Ended December 31, 2008
Residential	$ 106	$ 440	$ 480	$ 462
Industrial and commercial	117	588	637	636
Municipals	15	88	91	92
Other retail	20	114	118	108
Wholesale	5	18	29	107
	$ 263	$ 1,248	$ 1,355	$ 1,405

Revenue Recognition

Revenues are recorded based on service rendered to customers through month-end. Operating revenues are recorded based on energy deliveries through the end of the calendar month. Unbilled retail revenues result because customers' meters are read and bills are rendered throughout the month, rather than all being read at the end of the month. Unbilled revenues for a month are calculated by multiplying an estimate of unbilled kWh by the estimated average cents per kWh.

Accounts Receivable

Accounts receivable are reported in the Balance Sheets at the gross outstanding amount adjusted for an allowance for doubtful accounts.

Allowance for Doubtful Accounts

The allowance for doubtful accounts included in "Accounts receivable – customer" 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. The allowance for doubtful accounts included in "Accounts receivable – other" is composed of accounts aged more than four months. Accounts are written off as management determines them uncollectible.

The changes in the allowance for doubtful accounts were:

	Successor	Predecessor		
	December 31, 2010	October 31, 2010	December 31, 2009	December 31, 2008
Balance at beginning of period (a)	$ -	$ 3	$ 3	$ 2
Charged to income	1	(6)	(4)	(2)
Charged to balance sheets	5	6	4	3
Balance at end of period	$ 6	$ 3	$ 3	$ 3

(a) Successor beginning of period reflects revaluation of accounts receivable due to purchase accounting.

Cash

Cash Equivalents

All highly liquid investments with an original maturity of three months or less are considered to be cash equivalents.

Restricted Cash

Bank deposits and other cash equivalents that are restricted by agreement or that have been clearly designated for a specific purpose are classified as restricted cash. The change in restricted cash is reported as an investing activity on the Statements of Cash Flows. On the Balance Sheets, restricted cash is included in "Prepayments and other current assets". For KU, the December 31, 2010, balance of restricted cash was less than $1 million.

Fair Value Measurements

KU values certain financial assets and liabilities at fair value. Generally, the most significant fair value measurements relate to derivative assets and liabilities, investments in securities including investments in the pension and postretirement benefit plans and cash and cash equivalents. KU uses, as appropriate, a market approach (generally, data from market transactions), an income approach (generally, present value techniques) and/or a cost approach (generally, replacement cost) to measure the fair value of an asset or liability. These valuation approaches incorporate inputs such as observable, independent market data and/or unobservable data that management believes are predicated on the assumptions that market participants would use to price an asset or liability. These inputs may incorporate, as applicable, certain risks such as nonperformance risk, which includes credit risk.

KU prioritizes fair value measurements for disclosure by grouping them into one of three levels in the fair value hierarchy. The highest priority is given to measurements using level 1 inputs. The appropriate level assigned to a fair value measurement is based on the lowest level input that is significant to the fair value measurement in its entirety. The three levels of the fair value hierarchy are as follows:

- Level 1 - Observable inputs that reflect quoted prices (unadjusted) for identical assets or liabilities in active markets.
- Level 2 - Other inputs that are directly or indirectly observable in the marketplace.
- Level 3 - Unobservable inputs which are supported by little or no market activity.

Assessing the significance of a particular input requires judgment that considers factors specific to the asset or liability. As such, KU's assessment of the significance of a particular input may affect how the assets and liabilities are classified within the fair value hierarchy. See Note 5, Derivatives Financial Instruments, and Note 6, Fair Value Measurements, for further information on fair value measurements.

Investments

Equity Method Investment

KU's equity method investment, included in "Investment in unconsolidated venture" on the Balance Sheets, consists of its investment in EEI. KU owns 20% of the common stock of EEI, which owns and operates a 1,002 Mw summer capacity coal-fired plant and a 74 Mw summer capacity natural gas facility in southern Illinois. Through a power marketer affiliated with its majority owner, EEI sells its output to third parties. Although KU holds investment interest in EEI, it is not the primary beneficiary and is therefore not consolidated into the Company's financial statements. KU's investment in EEI is accounted for under the equity method of accounting and as of December 31, 2010 and 2009, totaled $30 million and $12 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. See Note 2, Acquisition by PPL, for further discussion regarding purchase accounting adjustments recognized for KU's investment in EEI.

The results of operations and financial position of EEI, KU's equity method investment, are summarized below.

Condensed income statement information for the years ended December 31 is as follows:

	2010 (unaudited)	2009	2008
Net sales	$ 343	$ 297	$ 514
Net income	16	10	142
KU's equity in earnings of EEI	3	1	30

Condensed balance sheet information as of December 31 is as follows:

	2010 (unaudited)	2009
Current assets	$ 62	$ 84
Long-lived assets	181	178
Total assets	$ 243	$ 262
Current liabilities	$ 113	$ 166
Long-term liabilities	72	50
Equity	58	46
Total liabilities and equity	$ 243	$ 262

Cost Method Investment

KU's cost method investment, included in "Investments in unconsolidated venture" on the Balance Sheets, consists of the Company's investment in OVEC. KU and 11 other electric utilities are owners of OVEC, which is located in Piketon, Ohio. OVEC owns and operates two coal-fired power plants, Kyger Creek Station in Ohio and Clifty Creek Station in Indiana with combined nameplate generating capacities of 2,390 Mw. OVEC's power is currently supplied to KU and 13 other companies affiliated with the various owners. Pursuant to current contractual agreements, KU owns 2.5% of OVEC's common stock and is contractually entitled to 2.5% of OVEC's output. Based on nameplate generating capacity, this would be approximately 60 Mw.

As of December 31, 2010 and 2009, KU's investment in OVEC totaled less than $1 million. KU is not the primary beneficiary of OVEC; therefore, it is not consolidated into the Company's financial statements and is accounted for under the cost method of accounting. The direct exposure to loss as a result of the Company's involvement with OVEC is generally limited to the value of its investment; however, KU may be conditionally responsible for a pro-rata share of certain OVEC obligations. See Note 2, Acquisition by PPL, and Note 13, Commitments and Contingencies, for further discussion regarding purchase accounting adjustments recognized, and KU's ownership interest and power purchase rights.

Long-Lived and Intangible Assets

Regulated Utility Plant

Regulated utility plant was stated at original cost for the Predecessor and adjusted to the net book value on November 1, 2010, the acquisition date, for the Successor. KU determined that fair value was equal to net book value at the acquisition date since KU's operations are conducted in a regulated environment. Original cost 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. KU has not recorded significant allowance for funds used during construction in accordance with FERC.

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.

Capitalized Software Cost

Included in "Property, plant and equipment" on the Balance Sheets are capitalized costs of software projects that were developed or obtained for internal use. These capitalized costs are amortized ratably over the expected lives of the projects when they become operational, generally not to exceed five years. Following are capitalized software costs and the accumulated amortization:

Successor		Predecessor	
December 31, 2010		December 31, 2009	
Carrying Amount	Accumulated Amortization (a)	Carrying Amount	Accumulated Amortization
$ 40	$ 1	$ 52	$ 13

(a) The accumulated amortization as of November 1, 2010, was netted against the carrying amount of the software as the fair value was determined to be equal to net book value for property, plant and equipment.

Amortization expense of capitalized software costs was as follows:

Successor	Predecessor		
November 1, 2010 through December 31, 2010	January 1, 2010 through October 31, 2010	Year Ended December 31,	
		2009	2008
$ 1	$ 6	$ 6	$ 5

The amortization of capitalized software is included in "Depreciation and amortization" on the Statements of Income.

Depreciation and Amortization

Depreciation is provided on the straight-line method over the estimated service lives of depreciable plant. The amounts provided as a percentage of depreciable plant were approximately:

Year	Percentage
2010	4.1%
2009	2.6%
2008	3.0%

Of the amount provided for depreciation, the following were related to the retirement, removal and disposal costs of long lived assets:

Year	Percentage
2010	0.6%
2009	0.4%
2008	0.5%

Goodwill, Intangible Assets and Asset Impairment

KU performs a quarterly review to determine if an impairment analyses is required for long-lived assets that are subject to depreciation or amortization. This review identifies changes in circumstances indicating that a long-lived asset's carrying value may not be recoverable. An impairment analysis will be performed if warranted, based on the review.

For a long-lived asset to be held and used, impairment exists when the carrying amount exceeds the sum of the undiscounted cash flows expected to result from the use and eventual disposition of the asset. If the asset is impaired, an impairment loss is recorded to adjust the asset's carrying amount to its fair value.

KU, as the result of PPL's acquisition of LKE, recorded the fair value of its coal contracts, emission allowances, EEI investment and OVEC power purchase contract. The difference between the fair value and the cost for these assets is being amortized over their useful lives based upon the pattern in which the economic benefits of the intangible assets are consumed or otherwise used. When determining the useful life of an intangible asset, including intangible assets that are renewed or extended, KU considers the expected use of the asset, the expected useful life of other assets to which the useful life of the intangible asset may relate and legal, regulatory, or contractual provisions that may limit the useful life. See Note 2, Acquisition by PPL, for methods used to determine the long-lived intangible assets' fair values. See Note 7, Goodwill and Intangible Assets, for the fair value amounts and amortization periods. The current intangible assets and long-term intangible assets are included in "Other intangible assets" on the Balance Sheets.

The Predecessor reported emission allowances in "Other materials and supplies" on the Balance Sheets. The emission allowances were not amortized; rather, they were expensed when consumed. The Predecessor did not recognize the coal contracts or the OVEC power purchase contract as these intangible assets were not derivatives.

In connection with PPL's acquisition of LKE, KU recorded goodwill on November 1, 2010. Goodwill represents the excess of the purchase price paid over the estimated fair value of the assets acquired and liabilities assumed in the acquisition of a business. Goodwill is tested annually for impairment during the fourth quarter and more frequently if management determines that a triggering event may have occurred that would more likely than not reduce the fair value of an operating unit below its carrying value. Goodwill impairment charges are not subject to rate recovery. See Note 7, Goodwill and Intangible Assets, for further discussion regarding the Company's goodwill and current test results.

Asset Retirement Obligations

KU recognizes various legal obligations associated with the retirement of long-lived assets as liabilities in the financial statements. Initially this obligation is measured at fair value. An equivalent amount is recorded as an increase in the value of the capitalized asset and allocated to expense over the useful life of the asset. Until the obligation is settled, the liability is increased, through the recognition of accretion expense in the Statements of Income, for changes in the obligation due to the passage of time. An offsetting regulatory asset is recognized to reverse the depreciation and accretion expense related to the ARO such that there is no income statement impact. The regulatory asset is relieved when the ARO has been settled. Estimated ARO costs and settlement dates, which affect the carrying value of various AROs and the related assets, are reviewed periodically to ensure that any material changes are incorporated into the latest estimate of the obligations. See Note 4, Asset Retirement Obligations, for further information on AROs.

Defined Benefits

KU employees benefit from both funded and unfunded retirement benefit plans. An asset or liability is recorded to recognize the funded status of all defined benefit plans with an offsetting entry to regulatory assets or regulatory liabilities. Consequently, the funded status of all defined benefit plans is fully recognized on the Balance Sheets.

The expected return on plan assets is determined based on the current level of expected return 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 is then weighted based on the current asset allocation.

The discount rate used for pensions, postretirement and post-employment plans by the Predecessor was determined using the Mercer Yield Curve. The expected return on assets assumption was 7.75%. Gains and losses in excess of 10% of the greater of the plan's projected benefit obligation or market value of assets were amortized on a straight-line basis over the average future service period of active participants. The market-related value of assets was equal to the fair market value of the assets.

The discount rate used by the Successor was determined by the Towers Watson Yield Curve based on the individual plan cash flows. The expected return on assets was reduced from 7.75% to 7.25%. The amortization period for the recognition of gains and losses for retirement plans was changed to reflect the Successor's amortization policy. Under the Successor's method, gains and losses in excess of 10% but less than 30% of the greater of the plan's projected benefit obligation or market-related value of assets, are amortized on a straight-line basis over the average future service period of active participants. Gains and losses in excess of 30% of the plan's projected benefit obligation or market-related value of assets are amortized on a straight-line basis over a period equal to one-half of the average future service period of active participants. The market-related value of assets for the qualified retirement plans will be equal to a five year smoothed asset value. Gains and losses in excess of the expected return will be phased-in over a five-year period, prospectively from November 1, 2010.

See Note 9, Pension and Other Postretirement Benefit Plans, for further information.

Other

Loss Accruals

Potential losses are accrued when information is available that indicates it is "probable" that a loss has been incurred, given the likelihood of uncertain future events, and the amount of the loss can be reasonably estimated. Accounting guidance defines "probable" as cases in which "the future event or events are likely to occur." KU continuously assesses potential loss contingencies for environmental remediation, litigation claims, regulatory penalties and other events.

KU does not record the accrual of contingencies that might result in gains unless recovery is assured.

Income Taxes

For the periods ended on or before October 31, 2010, KU was a subsidiary of E.ON U.S. and was part of E.ON U.S.'s direct parent's, E.ON US Investments Corp., consolidated U.S. federal income tax return. On November 1, 2010, KU became a part of PPL's consolidated U.S. federal income tax return.

Significant management judgment is required in developing KU's provision for income taxes primarily due to the uncertainty related to tax positions taken or expected to be taken in tax returns and the determination of deferred tax assets, liabilities and valuation allowances.

KU evaluates tax positions following a two-step process. The first step requires an entity to determine whether, based on the technical merits supporting a particular tax position, it is more likely than not (greater than a 50% chance) that the tax position will be sustained. This determination assumes that the relevant taxing authority will examine the tax position and is aware of all the relevant facts surrounding the tax position. The second step requires an entity to recognize in the financial statements the benefit of a tax position that meets the more-likely-than-not recognition criterion. The benefit recognized is measured at the largest amount of benefit that has a likelihood of realization, upon settlement, that exceeds 50%. The amounts ultimately paid upon resolution of issues raised by taxing authorities may differ materially from the amounts accrued and may materially impact the financial statements of KU.

Deferred income taxes reflect the net future tax effects of temporary differences between the carrying amounts of assets and liabilities for accounting purposes and their basis for income tax purposes, as well as the tax effects of net operating losses and tax credit carryforwards.

KU records valuation allowances to reduce deferred tax assets to the amounts that are more likely than not to be realized. KU considers the reversal of temporary differences, future taxable income and ongoing prudent and feasible tax planning strategies in initially recording and subsequently reevaluating the need for valuation allowances. If KU determines that it is able to realize deferred tax assets in the future in excess of recorded net deferred tax assets, adjustments to the valuation allowances increase income by reducing tax expense in the period that such determination is made. Likewise, if KU determines that it is not able to realize all or part of net deferred tax assets in the future, adjustments to the valuation allowances would decrease income by increasing tax expense in the period that such determination is made.

The provision for KU's deferred income taxes for regulated assets and liabilities is based upon the ratemaking principles reflected in rates established by the regulators. The difference in the provision for deferred income taxes for regulated assets and liabilities and the amount that otherwise would be recorded under GAAP is deferred and included on the Balance Sheets in "Regulatory liabilities".

KU defers investment tax credits when the credits are utilized and amortizes the deferred amounts over the average lives of the related assets.

See Note 10, Income Taxes, for further discussion regarding income taxes.

Leases

KU evaluates whether arrangements entered into contain leases for accounting purposes.

Materials and Supplies

Fuel and other materials and supplies inventories are accounted for using the average-cost method.

Fuel Costs

The cost of fuel for electric generation is charged to expense as used. See Note 3, Rates and Regulatory Matters, for a description of the FAC.

Debt

The Company's long-term debt includes $228 million of pollution control bonds, which are subject to tender for purchase at the option of the holder and to mandatory tender for purchase on the occurrence of certain events. The Successor has classified these bonds as long term because the Company has the intent and ability to utilize its $400 million credit facility, which matures in December 2014, to fund any mandatory purchases. Predecessor classified these bonds as current portion of long-term debt due to the tender for purchase provisions. The Predecessor presentation and the Successor presentation are both appropriate under GAAP. See Note 11, Long-Term Debt, and Note 12, Notes Payable and Other Short-Term Obligations, for more information on the Company's debt and credit facilities.

Unamortized Debt Expense

Debt expense is capitalized and amortized over the lives of the related bond issues using the straight line method, which approximates the effective interest method. Depending on the type of expense, the Successor capitalized debt expenses in long-term other regulatory assets or long-term other assets to align with the term of the debt the expenses were related. The Predecessor capitalized debt expenses in current or long-term other regulatory assets or other current or long-term other assets based on the amount of expense expected to be recovered within the next year through rate recovery. Both the Predecessor and the Successor amortize debt expenses over the lives of the related bond issues. The Predecessor presentation and the Successor presentation are both appropriate under regulatory practices and GAAP.

Recent Accounting Pronouncements

The following recent accounting pronouncement affected KU:

Fair Value Measurements

In January 2010, the FASB issued guidance related to fair value measurement disclosures requiring separate disclosure of amounts of significant transfers in and out of level 1 and level 2 fair value measurements and separate information about purchases, sales, issuances and settlements within level 3 measurements. This guidance is effective for the interim and annual reporting periods beginning after December 15, 2009, except for the disclosures about the roll-forward of activity in level 3 fair value measurements. Those disclosures are effective for fiscal years beginning after December 15, 2010 and for interim periods within those fiscal years. This guidance has no impact on the Company's results of operations, financial position, liquidity or disclosures.

Note 2 - Acquisition by PPL

On November 1, 2010, PPL completed its acquisition of LKE and its subsidiaries. The push-down basis of accounting was used to record the fair value adjustments of assets and liabilities on LKE at the acquisition date. PPL paid a cash consideration for LKE and its subsidiaries of $2,493 million as well as a capital contribution on November 1, 2010, of $1,565 million; included within this was the consideration paid for KU of $2,656 million. The allocation of the KU purchase price was based on the fair value of assets acquired and liabilities assumed.

The allocation of the purchase price to the fair value of assets acquired and liabilities assumed is as follows:

Current assets	$	364
Investments		30
Property, plant and equipment		4,531
Other intangible assets		178
Regulatory and other non-current assets		274
Current liabilities (excluding current portion of long-term debt)		(367)
Affiliated debt		(1,331)
Debt (current and non-current)		(352)
Other non-current liabilities		(1,278)
Net identifiable assets acquired		2,049
Goodwill		607
Total purchase price	$	2,656

Goodwill represents value paid for the rate regulated business of KU, which is located in a defined service area with a constructive regulatory environment, which provides for future investment, earnings and cash flow growth, as well as the talented and experienced workforce. KU's franchise values are being attributed to the going concern value of the business, and thus were recorded as goodwill rather than a separately identifiable intangible asset. None of the goodwill recognized is deductible for income tax purposes or included in regulated customer rates.

Adjustments to KU's assets and liabilities that contributed to goodwill were as follows:

The fair value adjustment on the EEI investment was calculated using the discounted cash flow valuation method. The result was an increase in KU's value of the investment in EEI; the fair value of EEI was calculated to be $30 million and a fair value adjustment of $18 million was recorded on KU. The fair value adjustment to EEI is amortized over the expected remaining useful life of plant and equipment at EEI, which is estimated to be over 20 years.

The pollution control bonds on KU had a fair value adjustment of $1 million. All variable bonds were valued at par while the fixed rate bonds were valued with a yield curve based on average credit spreads for similar bonds.

As a result of the purchase accounting associated with the acquisition, the following items had a fair value adjustment but no effect on goodwill as the offset was either a regulatory asset or liability. The regulatory asset or liability has been recorded to eliminate any ratemaking impact of the fair value adjustments:

- The value of OVEC was determined to be $39 million based upon an announced transaction by another owner. KU's stock was valued at less than $1 million and the power purchase agreement has been valued at $39 million. An intangible asset was recorded with the offset to regulatory liability and will be amortized using the units of production method until the power purchase agreement ends in March 2026.
- KU recorded an emission allowance intangible asset and regulatory liability as the result of adjusting the fair value of the emission allowances at KU. The emission allowance intangible of $9 million represents allocated and purchased SO_2 and NOx emission allowances that are unused as of the valuation date or allocated for use in future years. KU had previously recorded emission allowances as other materials and supplies. To conform to PPL's accounting policy all emission allowances are now recorded as intangible assets. The emission allowance intangible asset is amortized as the emission allowances are consumed, which is expected to occur through 2040.
- KU recorded a coal contract intangible asset of $145 million and non-current liability of $22 million on the Balance Sheets. An offsetting regulatory asset was recorded for those contracts with unfavorable terms relative to market. An offsetting regulatory liability was recorded for those contracts that had favorable terms relative to market. All coal contracts held by KU, wherein it had entered into arrangements to buy amounts of coal at fixed prices from counterparties at a future date, were fair valued. The intangible assets and other liabilities, as well as the regulatory assets and liabilities, are being amortized over the same terms as the related contracts, which expire through 2016.

The fair value of intangible assets and liabilities (e.g. contracts that have favorable or unfavorable terms relative to market), including coal contracts and power purchase agreements, as well as emission allowances, have been reflected on the Balance Sheets with offsetting regulatory assets or liabilities. Prior to the acquisition, KU recovered the cost of the coal contracts, power purchases and emission allowances and this rate treatment will continue after the acquisition. As a result, management believes the regulatory assets and liabilities created to offset the fair value adjustments meet the recognition criteria established by existing accounting guidance and eliminate any ratemaking impact of the fair value adjustments. KU's customer rates will continue to reflect these items (e.g. coal, purchased power, emission allowances) at their original contracted prices.

KU also considered whether a separate fair value should be assigned to KU's rights to operate within its various electric service areas but concluded that these rights only provided the opportunity to earn a regulated return and barriers to market entry, which in management's judgment is not considered a separately identifiable intangible asset under applicable accounting guidance; rather, it is considered going-concern value, or goodwill.

Note 3 - Rates and Regulatory Matters

The Company is subject to the jurisdiction of the FERC, Kentucky Commission, Virginia Commission and the Tennessee Regulatory Authority in virtually all matters related to electric utility regulation and as such, its accounting is subject to the regulated operations guidance of the FASB ASC. 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 the regulated operations guidance of the FASB ASC.

KU's Kentucky base rates are calculated based on a return on capitalization (common equity, long-term debt and notes payable) including certain regulatory adjustments to exclude non-regulated investments and environmental compliance plans recovered separately through the ECR mechanism. No regulatory assets or regulatory liabilities recorded at the time base rates were determined were excluded from the return on capitalization utilized in the calculation of Kentucky base rates. Therefore, a return is earned on all Kentucky regulatory assets existing at the time base rates were determined, except where such regulatory assets were offset by associated liabilities and thus, have no net impact on capitalization.

As a result of purchase accounting, certain fair value amounts, reflecting contracts that have favorable or unfavorable terms relative to market, were recorded on the Balance Sheets with offsetting regulatory assets or liabilities. Prior to the acquisition, KU recovered in customer rates the cost of the coal contracts, power purchases and emission allowances and this rate treatment will continue after the recognition criteria established by existing accounting guidance and eliminate any ratemaking impact of the fair value adjustments. KU's customer rates will continue to reflect these items (e.g. coal, purchased power, emission allowances) at their original contracted prices.

KU's Virginia base rates are calculated based on a return on rate base. All regulatory assets and liabilities are excluded from the return on rate base utilized in the calculation of Virginia base rates.

KU's wholesale requirements rates for municipal customers are calculated based on annual updates to a rate formula that utilizes a return on rate base. All regulatory assets and liabilities are excluded from the return on rate base utilized in the development of municipal rates.

<u>2010 Purchase and Sale Agreement with PPL</u>

On April 28, 2010, E.ON U.S. announced that a Purchase and Sale Agreement (the "Agreement") had been entered into among E.ON US Investments Corp., PPL and E.ON.

The transaction was subject to customary closing conditions, including the expiration or termination of the applicable waiting period under the Hart-Scott-Rodino Act, receipt of required regulatory approvals (including the FERC and state regulators in Kentucky, Virginia and Tennessee) and the absence of injunctions or restraints imposed by governmental entities.

Change of control and financing-related applications were filed on May 28, 2010 with the Kentucky Commission and on June 15, 2010 with the Virginia Commission and the Tennessee Regulatory Authority. An application with the FERC was filed on June 28, 2010. During the second quarter of 2010, a number of parties were granted intervenor status in the Kentucky Commission proceedings and data request filings and responses occurred. Early termination of the Hart-Scott-Rodino waiting period was received on August 2, 2010.

A hearing in the Kentucky Commission proceedings was held on September 8, 2010 at which time a unanimous settlement agreement was presented. In the settlement, KU committed that no base rate increases would take effect before January 1, 2013. The KU rate increases that took effect on August 1, 2010, were not impacted by the settlement. Under the terms of the settlement, KU retains the right to seek approval for the deferral of "extraordinary and uncontrollable costs." Interim rate adjustments will continue to be permissible during that period for existing fuel, environmental and demand-side management cost trackers. The agreement also substitutes an acquisition savings shared deferral mechanism for the requirement that the Utilities file a synergies plan with the Kentucky Commission. This mechanism, which will be in place until the earlier of five years or the first day of the year in which a base rate increase becomes effective, permits KU to earn up to a 10.75% return on equity. Any earnings above a 10.75% return on equity will be shared with customers on a 50%/50% basis. On September 30, 2010, the Kentucky Commission issued an Order approving the transfer of ownership of KU via the acquisition of E.ON U.S. by PPL, incorporating the terms of the submitted settlement. On October 19, 2010 and October 21, 2010, respectively, Orders approving the acquisition of E.ON U.S. by PPL were received from the Virginia Commission and the Tennessee Regulatory Authority. The Commissions' Orders contained a number of other commitments with regard to operations, workforce, community involvement and other matters.

In mid-September 2010, KU and other applicants in the FERC change of control proceeding reached an agreement with the protesters, whereby such protests have been withdrawn. The agreement, which was filed for consideration with the FERC, includes various conditional commitments, such as a continuation of certain existing undertakings with protesters in prior cases, an agreement not to terminate certain KU municipal customer contracts prior to January 2017, an exclusion of any transaction-related costs from wholesale energy and tariff customer rates to the extent that KU has agreed not to seek the same transaction-related costs from retail customers and agreements to coordinate with protesters in certain open or ongoing matters. A FERC Order approving the transaction was received on October 26, 2010 and the transaction was completed November 1, 2010.

2010 Kentucky Rate Case

In January 2010, KU filed an application with the Kentucky Commission requesting an increase in electric base rates of approximately 12%, or $135 million annually. In June 2010, KU and all of the intervenors, except the AG, agreed to stipulations providing for an increase in electric base rates of $98 million annually and filed a request with the Kentucky Commission to approve such settlement. An Order in the proceeding was issued in July 2010, approving all the provisions in the stipulations, including a return on equity range of 9.75 – 10.75%. The new rates became effective on August 1, 2010.

Virginia Rate Case

In June 2009, KU filed an application with the Virginia Commission requesting an increase in electric base rates for its Virginia jurisdictional customers in an amount of $12 million annually or approximately 21%. The proposed increase reflected a proposed rate of return on rate base of 8.586% based on a return on equity of 12%. During December 2009, KU and the Virginia Commission Staff agreed to a Stipulation and Recommendation authorizing base rate revenue increases of $11 million annually and a return on rate base of 7.846% based on a 10.5% return on common equity. In March 2010, the Virginia Commission issued an Order approving the stipulation, with the increased rates to be put into effect as of April 1, 2010. As part of the stipulation, KU refunded $1 million in interim rate amounts in excess of the ultimate approved rates.

FERC Wholesale Rate Case

In September 2008, KU filed an application with the FERC for increases in electric base rates applicable to wholesale power sales contracts or interchange agreements involving, collectively, twelve Kentucky municipalities. The application requested a shift from an all-in stated unit charge rate to an unbundled formula rate, including an annual adjustment mechanism. In 2009, the FERC issued an Order approving a settlement among the parties in the case, incorporating increases of approximately 3% from prior rates and a return on equity of 11%. In May 2010, KU submitted to the FERC the proposed current annual adjustments to the formula rates which incorporated certain proposed increases. Updated rates, including certain further adjustments from a review process involving wholesale requirements customers, became effective as of July 1, 2010, subject to certain review procedures by the wholesale requirements customers and the FERC.

By mutual agreement, the parties' settlement of the 2008 application left outstanding the issue of whether KU must allocate to the municipal customers a portion of renewable resources it may be required to procure on behalf of its retail ratepayers. An Order was issued by the FERC in July 2010, indicating that KU is not required to allocate a portion of any renewable resources to the twelve municipalities, thus resolving the remaining issue.

2008 Kentucky Rate Case

In July 2008, KU filed an application with the Kentucky Commission requesting an increase in electric base rates. In January 2009, KU, the AG, the KIUC and all other parties to the rate case filed a settlement agreement with the Kentucky Commission, under which KU's electric base rates decreased by $9 million annually. An Order approving the settlement agreement was received in February 2009. The new rates were implemented effective February 6, 2009.

Regulatory Assets and Liabilities

The following regulatory assets and liabilities were included in the Balance Sheets as of December 31:

	Successor 2010	Predecessor 2009
Current regulatory assets:		
ECR (a)	$ -	$ 28
FAC (a)	-	1
Coal contracts (b)	4	-
MISO exit (c)	-	2
Other (d)	5	1
Total current regulatory assets	$ 9	$ 32
Non-current regulatory assets:		
Pension and postretirement benefits (e)	$ 117	$ 105
Other non-current regulatory assets:		
Storm restoration (c)	57	59
ARO (f)	2	30
Unamortized loss on bonds (c)	12	12
Coal contracts (b)	14	-
MISO exit (a)	5	9
Unamortized debt expense	5	-
Other (d)	10	7
Subtotal other non-current regulatory assets	105	117
Total non-current regulatory assets	$ 222	$ 222
Current regulatory liabilities:		
Coal contracts	$ 16	$ -
ECR	12	-
FAC	2	-
DSM	5	3
Emission allowances	6	-
Other (g)	-	1
Total current regulatory liabilities	$ 41	$ 4
Non-current regulatory liabilities:		
Accumulated cost of removal of utility plant	$ 348	$ 335
Other non-current regulatory liabilities:		
Coal contracts	126	-
OVEC power purchase contract	38	-
Deferred income taxes – net	6	9
Postretirement benefits	10	9
Other (g)	6	7
Subtotal other non-current regulatory liabilities	186	25
Total non-current regulatory liabilities	$ 534	$ 360

(a) The FAC and ECR regulatory assets have separate recovery mechanisms with recovery within twelve months.
(b) Offsetting regulatory asset for fair value purchase accounting adjustments. See Note 2, Acquisition by PPL, for information on the purchase accounting adjustments.
(c) These regulatory assets are recovered through base rates.
(d) Other regulatory assets include:
    - The CMRG and KCCS contributions, an EKPC FERC transmission settlement agreement and rate case expenses, which are recovered through base rates.
    - The FERC jurisdictional portion of the EKPC FERC transmission settlement agreement included in current and non-current regulatory assets, recovered through the application of the annual OATT formula rate updates.
    - FERC jurisdictional pension expense, which will be requested in a future FERC rate case.
    - Offsetting regulatory asset for fair value purchase accounting adjustment for leases. See Note 2, Acquisition by PPL, for information on the purchase accounting adjustments.
    - The Virginia levelized fuel factor, which is a separate recovery mechanism with recovery within twelve months.
(e) KU generally recovers this asset through pension expense included in the calculation of base rates.
(f) When an asset with an ARO is retired, the related ARO regulatory asset will be offset against the associated ARO regulatory liability, ARO asset and ARO liability.
(g) Other regulatory liabilities includes the emission allowance purchase accounting offset, MISO exit and a change in accounting method for FERC jurisdictional spare parts.

ECR

KU recovers the costs of complying with the Federal Clean Air Act pursuant to Kentucky Revised Statute 278-183 as amended and those federal, state or local environmental requirements which apply to coal combustion wastes and by-products from facilities utilized for production of energy from coal, 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.

The Kentucky Commission requires reviews of the past operations of the environmental surcharge for six-month and two-year billing periods to evaluate the related charges, credits and rates of return, as well as to provide for the roll-in of ECR amounts to base rates each two-year period. In December 2010, the Kentucky Commission initiated a six-month review of the Utilities' environmental surcharge for the billing period ending October 2010. An order is expected in the second quarter of 2011. Also, in December 2010, an Order was issued approving the charges and credits billed through the ECR during the six-month period ending April 2010, as well as approving billing adjustments for under-recovered costs and the rate of return on capital. In May 2010, an Order was issued approving the amounts billed through the ECR during the six-month period ending October 2009, and the rate of return on capital and allowing recovery of the under-recovery position in subsequent monthly filings. In December 2009, an Order was issued approving the charges and credits billed through the ECR during the two-year period ending April 2009, an increase in the jurisdictional revenue requirement, a base rate roll-in and a revised rate of return on capital. In July 2009, an Order was issued approving the charges and credits billed through the ECR during the six-month period ending October 2008, as well as approving billing adjustments for under-recovered costs and the rate of return on capital. In August 2008, an Order was issued approving the charges and credits billed through the ECR during the six-month periods ending April

2008 and October 2007, and the rate of return on capital. In March 2008, an Order was issued approving the charges and credits billed through the ECR during the six-month and two-year periods ending October 2006 and April 2007, respectively, 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.

In June 2009, the Company filed an application for a new ECR plan with the Kentucky Commission seeking approval to recover investments in environmental upgrades and operations and maintenance costs at the Company's generating facilities. During 2009, KU reached a unanimous settlement with all parties to the case and the Kentucky Commission issued an Order approving KU's application. Recovery on customer bills through the monthly ECR surcharge for these projects began with the February 2010 billing cycle. At December 31, 2009, the Company had a regulatory asset of $28 million, which changed to a regulatory liability in the first quarter of 2010, as a result of these roll-in adjustments to base rates. At December 31, 2010, the regulatory liability balance was $12 million.

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 February 2009 expense month filing, which represents a slight increase over the previously authorized 10.50%. The 10.63% return on equity for the ECR mechanism was affirmed in the 2010 rate case.

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 billed amounts 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 December 2010, May 2010, November 2009, January 2009, June 2008 and January 2008, the Kentucky Commission issued Orders approving the charges and credits billed through the FAC for the six-month periods ending April 2010, August 2009, April 2009, April 2008, October 2007 and April 2007, respectively. In January 2009 the Kentucky Commission initiated routine examinations of the FAC for the two-year periods November 1, 2006 through October 31, 2008. The Kentucky Commission issued an Order in June 2009 approving the charges and credits billed through the FAC during the review periods.

KU also employs an FAC mechanism for Virginia customers using an average fuel cost factor based primarily on projected fuel costs. The Virginia levelized fuel factor allows fuel recovery based on projected fuel costs for the coming year plus an adjustment for any over- or under-recovery of fuel expenses from the prior year. At December 31, 2010 and 2009, KU had a regulatory asset of $5 million and less than $1 million, respectively.

In February 2010, KU filed an application with the Virginia Commission seeking approval of a decrease in its fuel cost factor beginning with service rendered in April 2010. An Order was issued in April 2010, resulting in an agreed upon decrease of 23% from the fuel factor in effect for April 2009 through March 2010.

In February 2009, KU filed an application with the Virginia Commission seeking approval of a 29% increase in its fuel cost factor beginning with service rendered in April 2009. In February 2009, the Virginia Commission issued an Order allowing the requested change to become effective on an interim basis. The Virginia Staff testimony filed in April 2009 recommended a slight decrease in the factor filed by KU. The Company indicated the Virginia Staff proposal was acceptable. A hearing was held in May 2009, with general resolution of remaining issues. In May 2009, the Virginia Commission issued an Order approving the revised fuel factor, representing an increase of 24%, effective May 2009.

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 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.

Coal Contracts

In November 2010, purchase accounting adjustments were recorded for the fair value of KU's coal contracts. Offsetting regulatory asset or liability for fair value purchase accounting adjustments eliminate any ratemaking impact of the fair value adjustments.

MISO

Following receipt of applicable FERC, Kentucky Commission and other regulatory Orders, related to proceedings that had been underway since July 2003, KU withdrew from the MISO effective September 1, 2006. Since the exit from the MISO, KU has been operating under a FERC approved OATT. KU now contracts with the TVA to act as its transmission reliability coordinator and SPP to function as its independent transmission operator, pursuant to FERC requirements. The contractual obligations with the TVA extend through August 2011 and with SPP through August 2012.

KU and the MISO 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 and made related FERC compliance filings. The Company's payment of this exit fee 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 providing KU with recovery of $4 million, of which $1 million was immediately recovered in 2008, with the remainder to be recovered over the seven years from 2008 through 2014 for credits realized from other payments the MISO will receive, plus interest.

In accordance with Kentucky Commission Orders approving the MISO exit, KU established a regulatory asset for the MISO exit fee, net of former MISO administrative charges collected via base rates through the base rate case test year ended April 30, 2008. The net MISO exit fee is subject to adjustment for possible future MISO credits and a regulatory liability for certain revenues associated with former MISO administrative charges, which were collected via base rates until February 6, 2009. The approved 2008 base rate case settlement provided for MISO administrative charges 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. This regulatory liability balance as of October 31, 2009, was included in the base rate case application filed on January 29, 2010. MISO exit fee credit amounts subsequent to October 31, 2009, will continue to accumulate as a regulatory liability until they 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. Based upon the 2008 FERC Orders, the Company 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. However, in May 2009, after a portion of the resettlement payments had been made, the FERC issued an Order on the requests for rehearing on one November 2008 Order which changed the effective date and reduced almost all of the previously accrued RSG resettlement costs. Therefore, these costs were reversed and a receivable was established for amounts already paid of less than $1 million. The MISO began refunding the amounts to the Company in June 2009 with full repayment by September 2009. In June 2009, the FERC issued an Order in the rate mismatch RSG proceeding, stating it will not require resettlements of the rate mismatch calculation from April 1, 2005 to November 4, 2007. An accrual had previously been recorded in 2008 for the rate mismatch issue for the time period April 25, 2006 to August 9, 2007, but no accrual had been recorded for the time period November 5, 2007 to November 9, 2008 based on the prior Order. Accordingly, the accrual for the former time period was reversed and an accrual for the latter time period was recorded in June 2009, with a net effect of $1 million of expense, substantially all of which was paid by September 2009.

In August 2009, the FERC determined that the MISO had failed to demonstrate that its proposed exemptions to real-time RSG charges were just and reasonable. In November 2009, the MISO made a compliance filing incorporating the rulings of the FERC Orders and a related task force, with a primary open issue being whether certain of the tariff changes are applied prospectively only or retroactively to approximately January 6, 2009.

In November 2009, the Utilities filed an application with the FERC to approve certain independent transmission operator arrangements to be effective upon the expiration of their current contract with SPP in September 2010. The application sought authority for KU and LG&E to function after such date as the administrators of their own OATT for most purposes. However, due to the lack of FERC approval for such an approach and the approaching expiration of the SPP contract, the Utilities determined the approach was no longer reasonably achievable without unacceptable delay and uncertainty. In July 2010, the Utilities entered into a new agreement with SPP to provide independent transmission operator services for a specified, limited time and removed its application for authority of administering its own OATT. The TVA, which currently acts as reliability coordinator, has also been retained under the existing service contract. The new agreement extends TVA services to August 2011 with no alterations or changes to the party's duties or responsibilities.

In August 2010, the FERC issued three Orders accepting most facets of several MISO RSG compliance filings. The FERC ordered the MISO to issue refunds for RSG charges that were imposed by the MISO on the assumption that there were rate mismatches for the period beginning November 5, 2007 through the present. There is no financial statement impact to the Company from this Order, as the MISO had anticipated that the FERC would require these refunds and had preemptively included them in the resettlements paid in 2009. The FERC denied the MISO's proposal to exempt certain resources from RSG charges, effective prospectively. The FERC accepted portions and rejected portions of the MISO's proposed RSG rate Redesign Proposal, which will be effective when the software is ready for implementation subject to further compliance filings. The impact of the Redesign Proposal on the Company cannot be estimated at this time.

Pension and Postretirement Benefits

KU accounts for pension and postretirement benefits in accordance with the compensation – retirement benefits guidance of the FASB ASC. This guidance requires employers to recognize the over-funded or under-funded status of a defined benefit pension and postretirement plan as an asset or liability on the Balance Sheets and to recognize through other comprehensive income the changes in the funded status in the year in which the changes occur. Under the regulated operations guidance of the FASB ASC, 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 the compensation – retirement benefits guidance of the FASB ASC. 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 its pension plan that is expected to be recovered and a regulatory liability representing the change in funded status of its postretirement benefit plan. The regulatory asset and liability will be adjusted annually as prior service cost and actuarial gains and losses are recognized in net periodic benefit cost.

Storm Restoration

In January 2009, a significant ice storm passed through KU's service area causing approximately 199,000 customer outages, followed closely by a severe wind storm in February 2009, causing approximately 44,000 customer outages. An application was filed with the Kentucky Commission in April 2009, requesting approval to establish a regulatory asset and defer for future recovery approximately $62 million in incremental operation and maintenance expenses related to the storm restoration. In September 2009, the Kentucky Commission issued an Order allowing the establishment of a regulatory asset of up to $62 million based on actual costs for storm damages and service restoration due to the January and February 2009 storms. In September 2009, a regulatory asset of $57 million was established for actual costs incurred and approval was received in KU's 2010 base rate case to recover this asset over a ten year period beginning August 1, 2010.

In September 2008, high winds from the remnants of Hurricane Ike passed through the service area causing significant outages and system damage. In October 2008, an application was filed with the

Kentucky Commission requesting approval to establish regulatory assets 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 establishment a regulatory asset of up to $3 million based on actual costs for storm damages and service restoration due to Hurricane Ike. In December 2008, a regulatory asset of $2 million was established for actual costs incurred and KU received approval in its 2010 base rate case to recover this asset over a ten year period, beginning August 1, 2010.

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.

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 $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. KU received approval from the Kentucky Commission in the Company's 2010 Kentucky base rate case to recover these regulatory assets over the requested period beginning August 1, 2010.

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.

KU incurred $2 million in expenses related to the development and support of the 2010 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 August 2010.

FERC Jurisdictional Pension Costs

Other regulatory assets include pension costs of $5 million incurred by the Company and allocated to its FERC jurisdictional ratepayers. The Company will seek recovery of this asset in the next FERC rate 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 were amortized through June 2009. KU earned a return of these amortized costs, which were included in jurisdictional operating expenses.

DSM

DSM consists of energy efficiency programs which are intended to reduce peak demand and delay the investment in additional power plant construction, provide customers with tools and information to become better managers of their energy usage and prepare for potential future legislation governing energy efficiency. KU's rates contain a DSM provision which 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. 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.

Emission Allowances

In November 2010, purchase accounting adjustments were recorded for the fair market value of KU's SO_2, NOx ozone season and NOx annual emission allowances. Offsetting regulatory assets or liabilities for fair value purchase accounting adjustments eliminate any ratemaking impact of the fair value adjustments. KU is granted SO_2 emission allowances through 2040 and NOx ozone season and NOx annual emission allowances through 2011.

Accumulated Cost of Removal of Utility Plant

As of December 31, 2010 and 2009, KU segregated the cost of removal, previously embedded in accumulated depreciation, of $348 million and $335 million, respectively, in accordance with FERC Order No. 631. For reporting purposes on the Balance Sheets, KU presented this cost of removal as a "Regulatory liability" pursuant to the regulated operations guidance of the FASB ASC.

OVEC Power Purchase Contract

In November 2010, purchase accounting adjustments were recorded for the fair value of the power purchase agreement between KU and OVEC. Offsetting regulatory liability for fair value purchase accounting adjustment eliminate any ratemaking impact of the fair value adjustments.

Deferred Income Taxes – Net

These regulatory 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.

Other Regulatory Matters

Kentucky Commission Report on Storms

In November 2009, the Kentucky Commission issued a report following review and analysis of the effects and utility response to the September 2008 wind storm and the January 2009 ice storm and possible utility industry preventative measures relating thereto. The report suggested a number of proposed or recommended preventative or responsive measures, including consideration of selective hardening of facilities, altered vegetation management programs, enhanced customer outage communications and similar measures. In March 2010, the Utilities filed a joint response reporting on their actions with respect to such recommendations. The response indicated implementation or completion of substantially all of the recommendations, including, among other matters, on-going reviews of system hardening and vegetation management procedures, certain test or pilot programs in such areas and fielding of enhanced operational and customer outage-related systems.

Wind Power Agreements

In August 2009, KU and LG&E filed a notice of intent with the Kentucky Commission indicating their intent to file an application for approval of wind power purchase contracts and cost recovery mechanisms. The contracts were executed in August 2009 and were contingent upon KU and LG&E receiving acceptable regulatory approvals. Pursuant to the proposed 20-year contracts, KU and LG&E would jointly purchase respective assigned portions of the output of two Illinois wind farms totaling an aggregate 109.5 Mw. In September 2009, the Utilities filed an application and supporting testimony with the Kentucky Commission. In October 2009, the Kentucky Commission issued an Order denying the Utilities' request to establish a surcharge for recovery of the costs of purchasing wind power. The Kentucky Commission stated that such recovery constitutes a general rate adjustment and is subject to the regulations of a base rate case. The Kentucky Commission Order provided for the request for approval of the wind power agreements to proceed independently from the request to recover the costs thereof via surcharges. In November 2009, KU and LG&E filed for rehearing of the Kentucky Commission's Order and requested that the matters of approval of the contract and recovery of the costs thereof remain the subject of the same proceeding. During December 2009, the Kentucky Commission issued data requests on this matter. In March 2010, the Utilities delivered notices of termination under provisions of the wind power contracts. The Utilities also filed a motion with the Kentucky Commission noting the termination of the contracts and seeking withdrawal of their application in the related regulatory proceeding. In April 2010, the Kentucky Commission issued an Order allowing the Utilities to withdraw their pending application.

Trimble County Asset Purchase and Depreciation

In July 2009, the Utilities notified the Kentucky Commission of the proposed sale from the Utilities of certain ownership interests in certain existing Trimble County generating station assets which were anticipated to provide joint or common use in support of the jointly-owned TC2 generating unit under construction at the station. The undivided ownership interests sold provide KU an ownership interest in these common assets proportional to its interest in TC2 and the assets' role in supporting both TC1 and TC2. In December 2009, the Utilities completed the sale transaction at a price of $48 million, representing the current net book value of the assets multiplied by the proportional interest being sold.

In August 2009, the Utilities jointly filed an application with the Kentucky Commission to approve new depreciation rates for applicable jointly-owned TC2-related generating, pollution control and other plant equipment and assets. During December 2009, the Kentucky Commission extended the data discovery process through January 2010 and authorized the Utilities on an interim basis to begin using the depreciation rates for TC2 as proposed in the application. In March 2010, the Kentucky Commission issued a final Order approving the use of the proposed depreciation rates on a permanent basis.

TC2 CCN Application and Transmission Matters

An application for a CCN for construction of TC2 was approved by the Kentucky Commission in November 2005. CCNs for two transmission lines associated with TC2 were issued by the Kentucky Commission in September 2005 and May 2006. All regulatory approvals and rights of way for one transmission line have been obtained.

KU's and LG&E's CCN for a transmission line associated with the TC2 construction has been challenged by certain property owners in Hardin County, Kentucky. Certain proceedings relating to CCN challenging and federal historic preservation permit requirements have concluded with outcomes in the Utilities' favor.

Completion of the transmission lines are also subject to standard construction permit, environmental authorization and real property or easement acquisition procedures. Certain Hardin County landowners have raised challenges to the transmission line in some of these forums as well.

With respect to the remaining on-going dispute, KU obtained various successful rulings during 2008 at the Hardin County Circuit Court confirming its condemnation rights. In August 2008, several landowners appealed such rulings to the Kentucky Court of Appeals and received a temporary stay preventing KU from accessing their properties. In May 2010, the Kentucky Court of Appeals issued an Order affirming the Hardin Circuit Court's finding that KU had the right to condemn easements on the properties. In May 2010, the landowners filed a petition for reconsideration with the Court of Appeals. In July 2010, the Court of Appeals denied that petition. In August, 2010, the landowners filed for discretionary review of that denial by the Kentucky Supreme Court.

Settlement discussions with the Hardin County property owners involved in the appeals of the condemnation proceedings have been unsuccessful to date. 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 brought challenging the same transmission line.

As a result of the aforementioned unresolved litigation delays encountered in obtaining access to certain properties in Hardin County, KU obtained easements to allow construction of temporary transmission facilities, bypassing those properties while the litigated issues are resolved. In September 2009, the Kentucky Commission issued an Order stating that a CCN was necessary for two segments of the proposed temporary facilities. In December 2009, the Kentucky Commission granted the CCNs for the relevant segments and the property owners have filed various motions to intervene, stay and appeal certain elements of the Kentucky Commission's recent orders. In January 2010, in respect of two of such proceedings, the Franklin County circuit court issued Orders denying the property owners' request for a stay of construction and upholding the prior Kentucky Commission denial of their intervenor status.

Consistent with the regulatory authorizations and the favorable outcome of the legal proceedings, the Utilities completed construction activities on the permanent transmission line easements. During 2010, the Utilities placed the transmission line into operation. While the Utilities are not currently able to predict the ultimate outcome and possible financial effects of the remaining legal proceedings, the Utilities do not believe the matter involves relevant or continuing risks to operations.

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 the Company from the requirements of the new hybrid model of regulation. In lieu of submitting an annual information filing, the Company 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.

Market-Based Rate Authority

In July 2006, the FERC issued an Order in KU's market-based rate proceeding accepting the Company's further proposal to address certain market power issues the FERC 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 balancing areas in which it may be deemed to have market power, subject to a restriction that such power will not be collusively re-sold back into such balancing areas. However, restrictions exist on sales by KU of power at market-based rates in the KU and LG&E and Big Rivers Electric Company balancing 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 the Company's power sales at balancing 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. As a condition of receiving and retaining market-based rate authority, KU must comply with applicable affiliate restrictions set forth in the FERC regulation. During September 2008, the Company submitted a regular triennial update filing under market-based rate regulations.

In June 2009, the FERC issued Order No. 697-C which generally clarified certain interpretations relating to power sales and purchases at balancing area interfaces or into balancing areas involving market power. In July 2009, the FERC issued an Order approving the Company's September 2008 application for market-based rate authority. During July 2009, affiliates of KU completed a transaction terminating certain prior generation and power marketing activities in the Big Rivers Electric Company balancing area, which termination should ultimately allow a filing to request a determination that the Company no longer is deemed to have market power in such balancing area.

KU conducts certain of its wholesale power sales activities in accordance with existing market-based rate authority principles and interpretations. Future FERC proceedings relating to Orders 697 or market-based rate authority could alter the amount of sales made at market-based versus cost-based rates. The Company's sales under market-based rate authority totaled less than $1 million for the year ended December 31, 2010.

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 Regional Reliability Organizations ("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. The Utilities are members of the SERC, which acts as KU's and LG&E's RRO. During December 2009 and April, July and August 2010, the Utilities submitted ten self-reports relating to various standards, which self-reports remain in the early stages of RRO review, and therefore, the Utilities are unable to estimate the outcome of these matters. Mandatory reliability standard settlements commonly also include non-penalty elements, including compliance steps and mitigation plans. Settlements with SERC proceed to NERC and FERC review before becoming final. While the Utilities believe they are in compliance with the mandatory reliability standards, events of potential non-compliance may be identified from time-to-time. The Utilities cannot predict such potential violations or the outcome of self-reports described above.

Integrated Resource Planning

Integrated resource planning ("IRP") 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 Kentucky Commission issued a staff report and Order closing this proceeding in December 2009. Pursuant to the Virginia Commission's December 2008 Order, KU filed its IRP in July 2009. The filing consisted of the 2008 Joint IRP filed by KU and LG&E with the Kentucky Commission along with additional data. The Virginia Commission has not established a procedural schedule for this proceeding. KU expects to file their next IRP in April 2011.

PUHCA 2005

PPL, KU's ultimate parent, is a holding company under PUHCA 2005. PPL, 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 standards within eighteen months after the enactment of EPAct 2005 and to commence consideration of Section 1254 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 and Section 1254 standards should not be adopted. However, all 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 program 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. The tariff was filed in October 2008, with an effective date of December 1, 2008. KU files annual reports on the program within 90 days of each plan year end for the three-year pilot period.

Green Energy Riders

In February 2007, KU and LG&E filed a Joint Application and Testimony for Proposed Green Energy Riders. 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. During November 2009, KU and LG&E filed an application to both continue and modify the existing Green Energy Programs. In February 2010, the Kentucky Commission approved the Utilities' application, as filed.

Home Energy Assistance Program

In July 2007, KU filed an application with the Kentucky Commission for the establishment of a Home Energy Assistance program. During September 2007, the Kentucky Commission approved the five-year program as filed, effective in October 2007. The programs were scheduled to terminate 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. As a condition in the settlement in the change of control proceeding before the Kentucky Commission in the PPL acquisition, the program was extended to September 2015.

Collection Cycle Revision

As part of its 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, in its rate case filed on July 29, 2008, 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 agreements approved in the rate cases in February 2009 changed the due date for customer bill payments to 12 days after bill issuance for both KU and LG&E and permitted KU's implementation of 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. In August 2008, the Kentucky Commission issued an Order consolidating the depreciation study with the base rate case proceeding. The approved settlement agreements in the rate cases established new depreciation rates effective February 2009. KU also filed the depreciation study with the Virginia Commission which approved the implementation of the new depreciation rates effective February 2009. Approval by the Virginia Commission does not preclude the rates from being raised as an issue by any party in KU's future base rate cases in Virginia.

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 permits 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 financial or other impact as a result of this Order. In April 2009, KU filed revised net metering tariffs and application forms pursuant to the Kentucky Commission's Order. The Kentucky Commission issued an Order in April 2009, which suspended for five months all net metering tariffs filed by the jurisdictional electric utilities. This suspension was intended to allow sufficient time for review of the filed tariffs by the Kentucky Commission Staff and intervening parties. In June 2009, the Kentucky Commission Staff held an informal conference with the parties to discuss issues related to the net metering tariffs filed by KU. Following this conference, the intervenors and KU resolved all issues and KU filed revised net metering tariffs with the Kentucky Commission. In August 2009, the Kentucky Commission issued an Order approving the revised tariffs.

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 non-regulated 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. The Kentucky Commission established a procedural schedule that allowed for data discovery and testimony through July 2009. In October 2009, the Kentucky Commission held an informal conference for the purpose of discussing issues related to the standard regarding the consideration of Smart Grid investments. A public hearing has not been scheduled in this matter.

Note 4 - Asset Retirement Obligations

A summary of KU's net ARO assets, ARO liabilities and regulatory assets established under the asset retirement and environmental obligations guidance of the FASB ASC follows:

	ARO Net Assets	ARO Liabilities	Regulatory Assets
As of December 31, 2008, Predecessor	$ 5	$ (32)	$ 28
ARO accretion and depreciation	(1)	(2)	2
As of December 31, 2009, Predecessor	4	(34)	30
ARO accretion and depreciation	-	(2)	2
Reclassification for retired assets	(1)	-	1
ARO revaluation - change in estimates	22	(24)	2
As of October 31, 2010, Predecessor	25	(60)	35
ARO accretion and depreciation	(1)	-	1
Purchase accounting - fair value adjustment	28	6	(34)
As of December 31, 2010, Successor	$ 52	$ (54)	$ 2

In September 2010, the Company performed a revaluation of its AROs as a result of recently proposed environmental legislation and improved ability to forecast asset retirement costs due to recent construction and retirement activity.

In November 2010, the Company recorded a purchase accounting adjustment to fair value AROs due to the PPL acquisition.

Pursuant to regulatory treatment prescribed under the regulated operations guidance of the FASB ASC, an offsetting regulatory credit was recorded in "Depreciation and amortization" in the Statements of Income for the Successor of $1 million in 2010 and $2 million for the Predecessor for the ARO accretion and depreciation expense. The offsetting regulatory credit recorded was $2 million in 2009 and 2008 for the ARO accretion and depreciation expense. The ARO liabilities are offset by cash settlements that have not yet been applied. Therefore, ARO net assets, ARO liabilities and regulatory assets balances do not net to zero due to the cash settlements.

KU's AROs are primarily related to the final retirement of assets associated with generating units. 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 the asset retirement and environmental obligations guidance of the FASB ASC, no material asset retirement obligations are recorded for transmission and distribution assets.

Note 5 – Derivative Financial Instruments

KU is subject to interest rate and commodity price risk related to on-going business operations. The Company's policies allow for the interest rate risk to be managed through the use of fixed rate debt, floating rate debt and interest rate swaps. Although the Company's policies allow for the use of interest rate swaps, as of December 31, 2010 and 2009, KU had no interest rate swaps outstanding. At December 31, 2010, KU's potential annual exposure to increased interest expense, based on a 10% increase in interest rates, was less than $1 million.

The Company does not net collateral against derivative instruments.

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 the derivatives and hedging guidance of the FASB ASC.

Energy trading and risk management contracts are valued using prices based on active trades from Intercontinental Exchange Inc. In the absence of a traded price, midpoints of the best bids and offers are the primary determinants of valuation. When sufficient trading activity data is unavailable, other inputs 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. 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 2010 or 2009. Changes in market pricing, interest rate and volatility assumptions were made during both years.

KU's financial assets and liabilities as of December 31, 2010 and December 31, 2009, arising from energy trading and risk management contracts not designated as hedging instruments accounted for at fair value total less than $1 million and are recorded in prepayments and other current assets and other current liabilities, respectively.

The Company maintains credit policies intended to minimize credit risk in wholesale marketing and trading activities by assessing the creditworthiness of potential counterparties prior to entering into transactions with them and continuing to evaluate their creditworthiness once transactions have been initiated. To further mitigate credit risk, KU seeks to enter into netting agreements or require cash deposits, letters of credit and parental company guarantees as security from counterparties. The Company uses ratings of S&P, Moody's and definitive qualitative and quantitative data to assess the financial strength of counterparties on an on-going basis. If no external rating exists, KU assigns an internally generated rating for which it sets appropriate risk parameters. As risk management contracts are valued based on changes in market prices of the related commodities, credit exposures are revalued and monitored on a daily basis. At December 31, 2010, 100% of the trading and risk management commitments were with counterparties rated BBB-/Baa3 equivalent or better. The Company has reserved against counterparty credit risk based on KU's own creditworthiness (for net liabilities) and its counterparty's creditworthiness (for net assets). The Company applies historical default rates within varying credit ratings over time provided by S&P or Moody's. At December 31, 2010 and December 31, 2009, counterparty credit reserves related to energy trading and risk management contracts were less than $1 million.

The net volume of electricity based financial derivatives outstanding at December 31, 2010 and December 31, 2009, was 129,199 Mwh and 315,600 Mwh, respectively. Cash collateral related to the energy trading and risk management contracts was less than $1 million at December 31, 2010 and December 31, 2009. Cash collateral related to the energy trading and risk management contracts is recorded in "Prepayments and other current assets" on the Balance Sheets.

KU manages the price risk of its estimated future excess economic generation capacity using market-traded forward contracts. Hedge accounting treatment has not been elected for these transactions; therefore, realized and unrealized gains and losses are included in the Statements of Income.

The following table presents the effect of market-traded forward contract derivatives not designated as hedging instruments on income:

		Successor	Predecessor		
Loss Recognized in Income	Location	November 1, 2010 through December 31, 2010	January 1, 2010 through October 31, 2010	Year Ended December 31, 2009	Year Ended December 31, 2008
Unrealized gain (loss)	Electric revenues	$ -	$ -	$ (1)	$ 1

Net realized gains and losses were zero for the period ended December 31, 2010 and less than $1 million for the periods ended October 31, 2010, December 31, 2009 and December 31, 2008.

Credit Risk Related Contingent Features

Certain of KU's derivative contracts contain credit contingent provisions which would permit the counterparties with which KU is in a net liability position to require the transfer of additional collateral upon a decrease in KU's credit rating. Some of these provisions would require KU to transfer additional collateral or permit the counterparty to terminate the contract if KU's credit rating were to fall below investment grade. Some of these provisions also allow the counterparty to require additional collateral upon each decrease in the credit rating at levels that remain above investment grade. In either case, if KU's credit rating were to fall below investment grade (i.e., below BBB- for S&P or Baa3 for Moody's), and assuming no assignment to an investment grade affiliate were allowed, most of these credit contingent provisions require either immediate payment of the net liability as a termination payment or immediate and ongoing full collateralization by KU on derivative instruments in net liability positions.

Additionally, certain of KU's derivative contracts contain credit contingent provisions that require KU to provide "adequate assurance" of performance if the other party has reasonable grounds for insecurity regarding KU's performance of its obligation under the contract. A counterparty demanding adequate assurance could require a transfer of additional collateral or other security, including letters of credit, cash and guarantees from a creditworthy entity. A demand for additional assurance would typically involve negotiations among the parties.

To determine net liability positions, KU uses the fair value of each agreement. At December 31, 2010, there were no energy trading and risk management derivative contracts with credit risk related contingent features that are in a liability position and collateral of less than $1 million was posted in the normal course of business. At December 31, 2010, a downgrade of the Company's credit rating below investment grade would have no effect on the energy trading and risk management derivative contracts or collateral required.

Note 6 - Fair Value Measurements

KU adopted the fair value guidance in the FASB ASC in two phases. Effective January 1, 2008, the Company adopted it for all financial instruments and non-financial instruments accounted for at fair value on a recurring basis, and effective January 1, 2009, the Company adopted it for all non-financial instruments accounted for at fair value on a non-recurring basis. The FASB ASC guidance clarifies that fair value is an exit price, representing the amount that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants. As such, fair value is a market-based measurement that should be determined based on assumptions that market participants would use in pricing an asset or a liability. As a basis for considering such assumptions, the FASB ASC guidance establishes a three-tier value hierarchy, which prioritizes the inputs used in the valuation methodologies in measuring fair value.

The carrying values and estimated fair values of KU's non-trading financial instruments follow:

	Successor		Predecessor	
	December 31, 2010		December 31, 2009	
	Carrying Value	Fair Value	Carrying Value	Fair Value
Long-term bonds	$ 1,841	$ 1,728	$ 351	$ 351
Long-term debt to affiliated company	-	-	1,331	1,401

The long-term fixed rate pollution control bond valuations reflect prices quoted by investment banks, which are active in the market for these instruments. First mortgage bond valuations reflect prices quoted from a third party service. The fair value of the long-term debt due to affiliated company is determined using an internal valuation model that discounts the future cash flows of each loan at current market rates as 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 has classified the applicable financial assets and liabilities that are accounted for at fair value into the three levels of the fair value hierarchy, as defined by the fair value measurements and disclosures guidance of the FASB ASC, as discussed in Note 1, Summary of Significant Accounting Policies.

The Company classifies its derivative cash collateral balances within level 1 based on the funds being held in a demand deposit account. The Company classifies its derivative energy trading and risk management contracts within level 2 because it values them using prices actively quoted for proposed or executed transactions, quoted by brokers or observable inputs other than quoted prices.

KU's financial assets and liabilities as of December 31, 2010 and 2009, arising from energy trading and risk management contracts accounted for at fair value on a recurring basis total less than $1 million. Cash collateral related to the energy trading and risk management contracts was less than $1 million at December 31, 2010 and December 31, 2009 each year.

There were no level 3 measurements for the periods ending December 31, 2010 and December 31, 2009.

Note 7 - Goodwill and Intangible Assets

In connection with PPL's acquisition of LKE, KU recorded goodwill on November 1, 2010. In addition, as of November 1, 2010, certain intangible assets were adjusted to their fair value and new intangible assets were recorded. See Note 2, Acquisition by PPL, for further information.

Goodwill

The Company performs its required annual goodwill impairment test in the fourth quarter. Impairment tests are performed between the annual tests when the Company determines that a triggering event has occurred that would, more likely than not, reduce the fair value of a reporting unit below its carrying value. The goodwill impairment test is comprised of a two-step process. In step 1, the Company identifies a potential impairment by comparing the estimated fair value of the regulated utilities (the goodwill reporting unit) to their carrying value, including goodwill, on the measurement date. If the estimated fair value exceeds its carrying amount, goodwill is not considered impaired. If the fair value is less than the carrying value, then step 2 is performed to measure the amount of impairment loss, if any. The step 2 calculation compares the implied fair value of the goodwill to the carrying value of the goodwill. The implied fair value of goodwill is equal to the excess of the Company estimated fair value over the fair values of its identified assets and liabilities. If the carrying value of goodwill exceeds the implied fair value of goodwill, an impairment loss is recognized in an amount equal to that excess (but not in excess of the carrying value).

In connection with PPL's acquisition of LKE on November 1, 2010, goodwill of $607 million was recorded on November 1, 2010. The allocation of the goodwill to KU was based on the net asset value of the Company. The goodwill represents value paid for the rate regulated business located in a defined service area with a constructive regulatory environment, which provides for future investment, earnings and cash flow growth, as well as the talented and experienced workforce. KU's franchise values are being attributed to the going concern value of the business and thus were recorded as goodwill rather than a separately identifiable intangible asset. None of the goodwill recognized is expected to be deductible for income tax purposes or included in customer rates. See Note 2, Acquisition by PPL, for further information.

For the 2010 annual impairment test, the primary valuation technique used was an income methodology based on management's estimates of forecasted cash flows for the Company, with those cash flows discounted to present value using rates commensurate with the risks of those cash flows. Management also took into consideration the acquisition price paid by PPL. The discounted cash flows for the Company was based on discrete financial forecasts developed by management for planning purposes and consistent with those given to PPL. Cash flows beyond the discrete forecasts were estimated using a terminal-value calculation, which incorporated historical and forecasted financial trends for the Company. No impairment resulted from the fourth quarter test, as the determined fair value of the Company was greater than its carrying value.

Other Intangible Assets

The gross carrying amount and the accumulated amortization of other intangible assets were as follows:

	Successor	
	December 31, 2010	
	Gross Carrying Amount	Accumulated Amortization
Subject to amortization:		
Coal contracts (a)	$ 145	$ 3
Land rights (b)	8	-
Emission allowances (c)	9	-
OVEC power purchase agreement (d)	39	1
Total other intangible assets	$ 201	$ 4

(a) The gross carrying amount represents the fair value of coal contracts recognized as a result of the 2010 acquisition by PPL. The weighted average amortization period of these contracts is 3 years. See Note 2, Acquisition by PPL, for further information.

(b) The gross carrying amount represents the fair value of land rights recognized as a result of adopting PPL's accounting policies in the Successor period. The weighted average amortization period of these rights is 17 years. See Note 1, Summary of Significant Accounting Policies, for further information.
(c) The gross carrying amount represents the fair value of emission allowances recognized as a result of the 2010 acquisition by PPL, as well as the reclassification of amounts from inventory to intangible assets as a result of adopting PPL's accounting policies in the Successor period. The weighted average amortization period of these emission allowances is 3 years. See Note 2, Acquisition by PPL, for further information.
(d) The gross carrying amount represents the fair value of the OVEC power purchase contract recognized as a result of the 2010 acquisition by PPL. The weighted average amortization period of the power purchase agreement is 8 years. See Note 2, Acquisition by PPL, for further information.

Current intangible assets and long-term intangible assets are included in "Other intangible assets" in their respective areas on the Balance Sheets in 2010. Intangible assets resulting from purchase accounting adjustments are not recoverable in rates.

Amortization expense, excluding consumption of emission allowances, was $4 million for the Successor in 2010. The estimated aggregate amortization expense for each of the next five years is as follows:

	Estimated Expense in Period Ended				
	2011	2012	2013	2014	2015
Aggregate amortization expense	$ 43	$ 25	$ 27	$ 24	$ 26

Note 8 - 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.

All of KU's customer receivables arise from deliveries of electricity. During 2010, the Company's ten largest customers accounted for less than 19% of volumes.

Effective August 4, 2009, KU and its employees represented by the IBEW Local 2100 entered into a three-year collective bargaining agreement. The agreement provides for negotiated increases or changes to wages, benefits or other provisions and for annual wage re-openers. KU and its employees represented by the USWA Local 9447-01 entered into a three-year collective bargaining agreement in August 2008. This 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 15% of the Company's workforce at December 31, 2010.

Note 9 - Pension and Other Postretirement Benefit Plans

KU employees benefit from both funded and unfunded retirement benefit plans. Its defined benefit pension plan covers employees hired by December 31, 2005. Employees hired after this date participate in the Retirement Income Account ("RIA"), a defined contribution plan. The postretirement plan includes health care benefits that are contributory, with participants' contributions adjusted annually. The Company 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 defined benefit plans' obligations, the fair value of assets and the funded status of the plans for November 1, 2010 through December 31, 2010, for the Successor, and for January 1, 2010 through October 31, 2010, and January 1, 2009 through December 31, 2009, for the Predecessor:

	Pension Benefits			Other Postretirement Benefits		
	Successor	Predecessor		Successor	Predecessor	
	2010	2010	2009	2010	2010	2009
Change in benefit obligation:						
Benefit obligation at beginning of period	$ 355	$ 316	$ 306	$ 84	$ 80	$ 75
Service cost	1	5	6	-	1	2
Interest cost	3	16	18	1	4	4
Benefits paid, net of retiree contributions	(3)	(14)	(18)	(1)	(4)	(5)
Actuarial (gain) loss and other	(2)	32	4	(1)	3	4
Benefit obligation at end of period	$ 354	$ 355	$ 316	$ 83	$ 84	$ 80

	Pension Benefits			Other Postretirement Benefits		
	Successor	Predecessor		Successor	Predecessor	
	2010	2010	2009	2010	2010	2009
Change in plan assets:						
Fair value of plan assets at beginning of period	$ 237	$ 219	$ 183	$ 20	$ 17	$ 12
Actual return on plan assets	7	20	41	-	1	3
Employer contributions	-	13	13	2	6	7
Benefits paid, net of retiree contributions	(3)	(14)	(18)	(1)	(4)	(5)
Administrative expenses and other	-	(1)	-	-	-	-
Fair value of plan assets at end of period	$ 241	$ 237	$ 219	$ 21	$ 20	$ 17
Funded status at end of period	$ (113)	$ (118)	$ (97)	$ (62)	$ (64)	$ (63)

Amounts Recognized in the Balance Sheets

The following tables provide the amounts recognized in the Balance Sheets and information for plans with benefit obligations in excess of plan assets plans for November 1, 2010 through December 31, 2010, for the Successor, and for January 1, 2010 through October 31, 2010, and January 1, 2009 through December 31, 2009, for the Predecessor:

	Pension Benefits			Other Postretirement Benefits		
	Successor	Predecessor		Successor	Predecessor	
	2010	2010	2009	2010	2010	2009
Regulatory assets	$ 117	$ 125	$ 105	$ -	$ -	$ -
Regulatory liabilities	-	-	-	(10)	(9)	(9)
Accrued benefit liability (non-current)	(113)	(118)	(97)	(62)	(64)	(63)

Amounts recognized in regulatory assets and liabilities for November 1, 2010 through December 31, 2010, for the Successor, and for January 1, 2010 through October 31, 2010, and January 1, 2009 through December 31, 2009, for the Predecessor:

	Pension Benefits			Other Postretirement Benefits		
	Successor	Predecessor		Successor	Predecessor	
	2010	2010	2009	2010	2010	2009
Transition obligation	$ -	$ -	$ -	$ 2	$ 2	$ 3
Prior service cost	3	4	5	1	1	2
Accumulated loss (gain)	114	121	100	(13)	(12)	(14)
Total regulatory assets and liabilities	$ 117	$ 125	$ 105	$ (10)	$ (9)	$ (9)

Additional information for plans with accumulated benefit obligations in excess of plan assets for November 1, 2010 through December 31, 2010, for the Successor, and for January 1, 2010 through October 31, 2010, and January 1, 2009 through December 31, 2009, for the Predecessor:

	Pension Benefits			Other Postretirement Benefits		
	Successor	Predecessor		Successor	Predecessor	
	2010	2010	2009	2010	2010	2009
Benefit obligation	$ 354	$ 355	$ 316	$ 83	$ 84	$ 80
Accumulated benefit obligation	299	299	268	-	-	-
Fair value of plan assets	241	237	219	21	20	17

The amounts recognized in regulatory assets and liabilities for November 1, 2010 through December 31, 2010, for the Successor, and for January 1, 2010 through October 31, 2010, and January 1, 2009 through December 31, 2009, for the Predecessor:

	Pension Benefits			Other Postretirement Benefits		
	Successor	Predecessor		Successor	Predecessor	
	2010	2010	2009	2010	2010	2009
Net (gain) loss arising during the period	$ (6)	$ 26	$ (22)	$ (1)	$ 2	$ 2
Amortization of prior service cost	-	(1)	(1)	-	-	-
Amortization of transitional obligation	-	-	-	-	(2)	(1)
Amortization of loss	(2)	(5)	(9)	-	-	-
Total amounts recognized in regulatory assets and liabilities	$ (8)	$ 20	$ (32)	$ (1)	$ -	$ 1

For discussion of the pension and postretirement regulatory assets, see Note 3, 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 Servco employees who provide services to KU. The Servco costs are allocated to KU based on employees' labor charges and are approximately 51%, 49% and 46% of Servco's costs for 2010, 2009 and 2008, respectively.

	Pension Benefits					
	Successor			Predecessor		
	November 1, 2010 through December 31, 2010			January 1, 2010 through October 31, 2010		
	KU	Servco Allocation to KU	Total KU	KU	Servco Allocation to KU	Total KU
Service cost	$ 1	$ 1	$ 2	$ 5	$ 5	$ 10
Interest cost	3	2	5	16	6	22
Expected return on plan assets	(3)	(1)	(4)	(14)	(5)	(19)
Amortization of prior service cost	-	-	-	1	1	2
Amortization of actuarial gain	2	-	2	5	2	7
Net periodic benefit cost	$ 3	$ 2	$ 5	$ 13	$ 9	$ 22

	Pension Benefits					
	Predecessor - Year Ended December 31, 2009			Predecessor - Year Ended December 31, 2008		
	KU	Servco Allocation to KU	Total KU	KU	Servco Allocation to KU	Total KU
Service cost	$ 6	$ 5	$ 11	$ 6	$ 4	$ 10
Interest cost	18	7	25	18	6	24
Expected return on plan assets	(15)	(4)	(19)	(21)	(5)	(26)
Amortization of prior service cost	1	1	2	1	1	2
Amortization of actuarial gain	9	2	11	-	-	-
Net periodic benefit cost	$ 19	$ 11	$ 30	$ 4	$ 6	$ 10

	Other Postretirement Benefits					
	Successor			Predecessor		
	November 1, 2010 through December 31, 2010			January 1, 2010 through October 31, 2010		
	KU	Servco Allocation to KU	Total KU	KU	Servco Allocation to KU	Total KU
Service cost	$ -	$ -	$ -	$ 1	$ 1	$ 2
Interest cost	1	-	1	4	-	4
Expected return on plan assets	-	-	-	(1)	-	(1)
Amortization of transition obligation	-	-	-	1	-	1
Net periodic benefit cost	$ 1	$ -	$ 1	$ 5	$ 1	$ 6

	Other Postretirement Benefits					
	Predecessor - Year Ended December 31, 2009			Predecessor Year Ended December 31, 2008		
	KU	Servco Allocation to KU	Total KU	KU	Servco Allocation to KU	Total KU
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 transition obligation	1	-	1	1	-	1
Net periodic benefit cost	$ 6	$ 1	$ 7	$ 6	$ 1	$ 7

The estimated amounts that will be amortized from regulatory assets and liabilities into net periodic benefit cost in 2011 are shown in the following table:

	Pension Benefits	Other Postretirement Benefits
Regulatory assets and liabilities:		
Net actuarial loss	$ 8	$ -
Prior service cost	1	1
Transition obligation	-	1
Total regulatory assets and liabilities amortized during 2011	$ 9	$ 2

The weighted average assumptions used in the measurement of KU's pension and postretirement benefit obligations for November 1, 2010 through December 31, 2010, for the Successor, and for January 1, 2010 through October 31, 2010, and January 1, 2009 through December 31, 2009, for the Predecessor are shown in the following table:

	Successor	Predecessor	
	December 31, 2010	October 31, 2010	December 31, 2009
Discount rate – pension benefits	5.52%	5.46%	6.13%
Discount rate – postretirement benefits	5.12%	4.96%	5.82%
Rate of compensation increase	5.25%	5.25%	5.25%

For the first ten months of 2010, the discount rates used to determine the pension and postretirement benefit obligations and the period expense were determined using the Mercer Pension Discount Yield Curve. This model takes the plans' cash flows and matches them to a yield curve that provides the equivalent yields on zero-coupon corporate bonds for each maturity. The discount rate is the single rate that produces the same present value of cash flows. The selection of the various discount rates represents the equivalent single rate under a broad-market AA yield curve constructed by Mercer.

For the last two months of 2010, the Towers Watson Yield Curve was used to determine the discount rate. This model also starts with an analysis of the expected benefit payment stream for its plans. This information is first matched against a spot-rate yield curve. A portfolio of Aa-graded non-callable (or callable with make-whole provisions) bonds, with a total amount outstanding in excess of $667 billion, serves as the base from which those with the lowest and highest yields are eliminated to develop the ultimate yield curve. The results of this analysis are considered together with other economic data and movements in various bond indices to determine the discount rate assumption.

The weighted average assumptions used in the measurement of KU's pension and postretirement net periodic benefit costs for November 1, 2010 through December 31, 2010, for the Successor, and for January 1, 2010 through October 31, 2010, and January 1, 2009 through December 31, 2009, for the Predecessor are shown in the following table:

	Successor	Predecessor		
	2010	2010	2009	2008
Discount rate - pension	5.45%	5.46%	6.25%	6.66%
Discount rate - postretirement	4.94%	5.82%	6.36%	6.56%
Expected long-term return on plan assets	7.25%	7.75%	8.25%	8.25%
Rate of compensation increase	5.25%	5.25%	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 current asset allocation to develop the expected long-term rate of return on assets assumption for the portfolio. The Company has determined that the 2011 expected long-term rate of return on assets assumption should be 7.25%.

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

- A 1% change in the assumed discount rate would have a $39 million positive or negative impact to the 2010 accumulated benefit obligation and an approximate $51 million positive or negative impact to the 2010 projected benefit obligation.
- A 25 basis point change in the expected rate of return on assets would have resulted in less than a $1 million positive or negative impact to 2010 pension expense.
- A 25 basis point increase in the rate of compensation increase would have a $3 million negative impact to the 2010 projected benefit obligation.

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 the first ten months of 2010. The rate was assumed to decrease gradually to 4.5% by 2029 and remain at that level thereafter. For the last two months of 2010, an 8% annual increase in the per capita cost of covered health care benefits was assumed and the rate was assumed to decrease gradually to 5.5% by 2019. For 2011, a 9% annual increase in the per capita cost of covered health care benefits is assumed and the rate is assumed to decrease gradually to 5.5% by 2019. This change in the length of the health care trend was made to conform to PPL's accounting policies.

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 to the 2010 total of service and interest costs components and an increase or decrease of $4 million in year end 2010 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 costs and the estimated gross amount of Medicare subsidy receipts:

	Pension Benefits	Other Postretirement Benefits	Medicare Subsidy Receipts
2011	$ 18	$ 6	$ 1
2012	18	6	-
2013	18	6	1
2014	18	7	-
2015	18	7	1
2016-2020	106	36	3

Plan Assets

The following table shows the pension plan's weighted average asset allocation by asset category at December 31:

	Target Range	Successor 2010	Predecessor 2009
Equity securities	45% - 75%	56%	59%
Debt securities	30% - 50%	24%	40%
Other	0% - 10%	20%	1%
Totals		100%	100%

The investment policy of the pension plans was developed in conjunction with financial and actuarial consultants, investment advisors and legal counsel. The goal of the investment policy is to preserve the capital of the pension plans' assets and maximize investment earnings in excess of inflation with acceptable levels of volatility. The return objective is to exceed the benchmark return for the policy index comprised of the following: Russell 3000 Index, MSCI-EAFE Index, Barclays Capital Aggregate and Barclays Capital 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 over rolling three and five-year periods. 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 are either 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.

KU has classified plan assets that are accounted for at fair value into the three levels of the fair value hierarchy, as defined by the fair value measurements and disclosures guidance of the FASB ASC. See Note 6, Fair Value Measurements, for further information.

A financial instrument's level within the fair value hierarchy is based on the lowest level of any input that is significant to the fair value measurement. Valuation techniques used need to maximize the use of observable inputs and minimize the use of unobservable inputs.

A description of the valuation methodologies used to measure plan assets at fair value is provided below:

Money market funds: These investments are public investment vehicles valued using $1 for the net asset value. The money market funds are classified within level 2 of the valuation hierarchy.

Common/collective trusts: Valued based on the beginning of year value of the plan's interests in the trust plus actual contributions and allocated investment income (loss) less actual distributions and allocated administrative expenses. Quoted market prices are used to value investments in the trust, with the exception of the GAC. The fair value of certain other investments for which quoted market prices are not available are valued based on yields currently available on comparable securities of issuers with similar credit ratings. The common/collective trusts are classified within level 2 of the valuation hierarchy.

The preceding methods described may produce a fair value that may not be indicative of net realizable value or reflective of future fair values. Furthermore, although the Company believes its valuation methods are appropriate and consistent with other market participants, the use of different methodologies or assumptions to determine the fair value of certain financial instruments could result in a different fair value measurement at the reporting date.

Prior to the acquisition, the GAC was considered an immediate participation guarantee contract which was not included in the fair value table. In accordance with the plan accounting guidance of the FASB ASC, the cost incurred to purchase the GAC prior to March 20, 1992, was permitted to be carried at contract value, since it is a contract with an insurance company and prior to the acquisition it was excluded from the table above. The cost incurred to fund the GAC after March 20, 1992, was carried at contract value in accordance with the plan accounting guidance of the FASB ASC, since it was a contract that incorporates mortality and morbidity risk. Contract value represents cost plus interest income less distributions for benefits and administrative expenses. To conform to PPL's accounting methods, the John Hancock GAC was classified in the fair value table as a level 3 and as "other" rather than "debt securities" in the asset allocation table for the period ended December 31, 2010.

The following table sets forth, by level within the fair value hierarchy, the plan's assets at fair value at December 31:

	Successor		Predecessor	
	Level 2	Level 3	Level 2	Level 3
Money market funds	$ 2	$ -	$ 2	$ -
Common/collective trusts	213	-	186	-
John Hancock - GAC	-	47	-	-
Total investments at fair value	$ 215	$ 47	$ 188	$ -

The following table sets forth a reconciliation of changes in the fair value of the plan's level 3 assets for the following period:

	Successor
Balance at November 1, 2010	$ -
Purchases	1
Transfers into level 3	46
Balance at December 31, 2010	$ 47

There are no assets categorized as level 1 as of December 31, 2010 and December 31, 2009.

Contributions

KU made discretionary contributions to the pension plan of $13 million in 2010 and 2009. Servco made $9 million and $8 million in discretionary contributions to its pension plan in 2010 and 2009, 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. The Company made contributions totaling $43 million in January 2011.See Note 18, Subsequent Events, for further information.

The Company made contributions to its other postretirement benefit plan of $8 million in 2010 and $7 million in 2009. In 2011, the Company 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's plan met the minimum funding requirements as defined by the Pension Protection Act of 2006 for years ended December 31, 2010 and 2009.

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 employees' contributions. The costs of this matching were $3 million in 2010, 2009 and 2008.

KU also makes contributions to RIAs within the thrift savings plans for certain employees not covered by the non-contributory defined benefit pension plan. These employees consist of those hired after December 31, 2005. The Company makes these contributions based on years of service and the employees' wage and salary levels, and makes them in addition to the matching contributions discussed above. The amounts contributed by the Company under this arrangement were less than $1 million in 2010, 2009 and 2008.

Health Care Reform

In March 2010, Health Care Reform (the Patient Protection and Affordable Care Act of 2010) was signed into law. Many provisions of Health Care Reform do not take effect for an extended period of time and many aspects of the law which are currently unclear or undefined will likely be clarified in future regulations.

During 2010, KU recorded an income tax expense of less than $1 million to recognize the impact of the elimination of the tax deduction related to the Medicare Retiree Drug Subsidy that becomes effective in 2013.

Specific provisions within Health Care Reform that may impact KU include:

- Beginning in 2011, requirements extend dependent coverage up to age 26, remove the $2 million lifetime maximum and eliminate cost sharing for certain preventative care procedures.
- Beginning in 2018, a potential excise tax is expected on high-cost plans providing health coverage that exceeds certain thresholds.

The Company has evaluated these provisions of Health Care Reform on its benefit programs in consultation with its actuarial consultants and has determined that the excise tax will not have an impact on its postretirement medical plans. The requirement to extend dependent coverage up to age 26 is not expected to have a significant impact on active or retiree medical costs. The Company will continue to monitor the potential impact of any changes to the existing provisions and implementation guidance related to Health Care Reform on its benefit programs.

Note 10 - Income Taxes

KU's federal income tax return is included in a United States consolidated income tax return filed by LKE's direct parent. Prior to October 31, 2010 the return was included in the consolidated return of E.ON US Investments Corp. Due to the acquisition by PPL, the return will be included in the consolidated PPL return beginning November 1, 2010, 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. The Company also files income tax returns in various state jurisdictions. While 2007 and later years are open under the federal statute of limitations, Revenue Agent Reports for 2007-2008 have been received from the IRS, effectively closing these years to additional audit adjustments. Tax years beginning with 2007 were examined under an IRS program, 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 federal tax return. For 2008, the IRS allowed additional deductions in connection with the Company's application for a change in repair deductions and disallowed certain bonus depreciation claimed on the original return. The net temporary tax impact for the Company was a $12 million reduction in tax and was recorded in the second quarter of 2010. The 2009 federal return was filed in the third quarter of 2010 and the IRS issued a Partial Acceptance Letter in connection with CAP. The IRS is continuing to review bonus depreciation, storms and other repairs. No net material adverse impact is expected from these remaining areas. The short tax year beginning January 1, 2010 through October 31, 2010, is also being examined under CAP. No material items have been raised by the IRS at this time. The two month period beginning November 1, 2010 and ending December 31, 2010 is not currently under examination.

Additions and reductions of uncertain tax positions during 2010, 2009 and 2008 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. If recognized, the less than $1 million of unrecognized tax benefits would reduce the effective income tax rate.

The amount KU recognized as interest expense and interest accrued related to unrecognized tax benefits was less than $1 million for the twelve month periods ended and as of December 31, 2010, 2009 and 2008. The interest expense and interest accrued is based on IRS and Kentucky Department of Revenue large corporate interest rates for underpayment of taxes. At the date of adoption, the Company accrued less than $1 million in interest expense on uncertain tax positions. KU records the interest as "Interest expense" and penalties, if any, as "Operating expenses" on the Statements of Income and "Other current liabilities" on the Balance Sheets, on a pre-tax basis. No penalties were accrued by the Company through December 31, 2010.

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

	Successor	Predecessor		
	November 1, 2010 through December 31, 2010	January 1, 2010 through October 31, 2010	Year Ended December 31,	
			2009	2008
Current:				
Federal	$ 13	$ 46	$ (5)	$ 46
State	3	9	1	10
Deferred:				
Federal – net	4	20	43	(10)
State – net	-	3	7	(3)
Investment tax credit – deferred	-	-	21	25
Total income tax expense	$ 20	$ 78	$ 67	$ 68

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 an investment tax credit 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, which includes a full depreciation basis adjustment for the amount of the credit. KU's portion of the TC2 tax credit is approximately $101 million. Based on eligible construction expenditures incurred, KU recorded an investment tax credit of $21 million and $25 million in 2009 and 2008, respectively, decreasing current federal income taxes. As of December 31, 2009, KU had recorded its maximum credit of $101 million. The income tax expense impact from amortizing this credit over the life of the related property began when the facility was placed in service in January 2011.

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. The plaintiffs voluntarily dismissed their complaint in August 2010.

Components of deferred income taxes included in the Balance Sheets are shown below:

	Successor December 31, 2010	Predecessor December 31, 2009
Deferred income tax liabilities:		
Depreciation and other plant-related items	$ 347	$ 303
Regulatory assets and other	133	69
Total deferred income tax liabilities	480	372
Deferred income tax assets:		
Regulatory liabilities and other	80	-
Income taxes due to customers	2	4
Pensions and related benefits	9	17
Liabilities and other	19	18
Total deferred income tax assets	110	39
Net deferred income tax liabilities	$ 370	$ 333
Balance sheet classification:		
Prepayments and other current assets	$ (6)	$ (3)
Deferred income taxes (non-current)	376	336
Net deferred income tax liabilities	$ 370	$ 333

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

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

	Successor	Predecessor		
	November 1, 2010 through December 31, 2010	January 1, 2010 through October 31, 2010	Year Ended December 31, 2009	Year Ended December 31, 2008
Statutory federal income tax expense	$ 19	$ 77	$ 70	$ 79
State income taxes – net of federal benefit	2	8	5	5
Qualified production activities deduction	(1)	(4)	(1)	(3)
Dividends received deduction related to EEI investment	-	-	(3)	(8)
Reversal of excess deferred taxes	-	(2)	(2)	(1)
Other differences – net	-	(1)	(2)	(4)
Income tax expense	$ 20	$ 78	$ 67	$ 68
Effective income tax rate	36.4%	35.8%	33.5%	30.1%

The Tax Relief, Unemployment Reauthorization and Job Creation Act of 2010, enacted December 17, 2010 provided, among other provisions, certain incentives related to bonus depreciation and 100% expensing of qualifying capital expenditures. KU benefited from these new provisions by reducing its 2010 current federal income tax expense. This reduction in federal taxable income for KU does, however, result in a reduction of KU's Section 199 Manufacturing deduction, which is based on manufacturing taxable income and correspondingly increases income tax expense. The impact from these changes on 2010 was not material; however, KU anticipates a significant reduction of taxable income in 2011 and 2012 and a corresponding loss of most, if not all, of the Section 199 Manufacturing deduction for the following two years.

Note 11 - Long-Term Debt

As summarized below, at December 31, 2010, long-term debt consisted of first mortgage bonds and secured pollution control bonds. At December 31, 2009, long-term debt and the current portion of long-term debt consisted primarily of pollution control bonds and long-term loans from affiliated companies.

	Successor		Predecessor	
	2010		2009	
Current portion of long-term debt to affiliates	$	-	$	33
Long-term debt to affiliated companies		-		1,298
Secured first mortgage bonds, net of debt discount and amortization of debt discount		1,500		-
Pollution control revenue bonds, collateralized by first mortgage bonds		351		351
Fair value adjustment from purchase accounting		1		-
Unamortized discount		(11)		-
Total long-term debt		1,841		1,682
Less current portion		-		261
Long-term debt, excluding current portion	$	1,841	$	1,421

	Stated Interest Rates	Maturities	Debt Amounts	
Successor				
Outstanding at December 31, 2010:				
Current portion	N/A	N/A	$	-
Non-current portion	Variable – 6.00%	2015-2040		1,841
Predecessor				
Outstanding at December 31, 2009:				
Current portion	Variable – 4.240%	2010-2034	$	261
Non-current portion	Variable – 7.035%	2011-2037		1,421

As of December 31, 2009, long-term debt includes $228 million of pollution control bonds that were classified as current portion 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 2002 Series A and B, 2004 Series A, 2006 Series B and 2008 Series A; Muhlenberg County 2002 Series A; and Mercer County 2000 Series A and 2002 Series A. Maturity dates for these bonds range from 2023 to 2034. As of December 31, 2009, the bonds were classified as current portion of long-term debt because investors could put the bonds back to the Company within one year. As of December 31, 2010, the bonds were reclassified as long-term debt. See Note 1, Summary of Significant Accounting Policies, for changes in classification.

Pollution control bonds are obligations of KU issued in connection with tax-exempt pollution control bonds by various counties in Kentucky. A loan agreement obligates the Company to make debt service payments to the counties in amounts equal to the debt service due from the counties on the related pollution control bonds. Depending on the type of expense, the Successor capitalized debt expenses in long-term other regulatory assets or long-term other assets to align with the term of the debt for which the expenses were related. The Predecessor capitalized debt expenses in current or long-term other regulatory assets or other current or long-term other assets based on the amount of expense expected to be recovered within the next year through rate recovery. Both Predecessor and Successor amortized debt expenses over the lives of the related bond issues. The Predecessor presentation and the Successor presentation are both appropriate under regulatory practices and GAAP.

In October 2010, in order to secure their respective obligations with respect to the pollution control bonds, KU issued first mortgage bonds to the pollution control bond trustees. KU's first mortgage bonds contain terms and conditions that are substantially parallel to the terms and conditions of the counties' debt, but provide that obligations are deemed satisfied to the extent of payments under the related loan agreement, and thus generally require no separate payment of principal and interest except under certain circumstances, including should KU default on the respective loan agreement. Also in October 2010, one national rating agency revised downward the short-term credit rating of the pollution control bonds and the Company's issuer rating as a result of the pending acquisition by PPL.

Several series of KU's pollution control bonds are insured by monoline bond insurers whose ratings have been reduced due to exposures relating to insurance of sub-prime mortgages. At December 31, 2010, 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. Since 2008, interest rates increased and the Company experienced "failed auctions" when there were insufficient bids for the bonds. When a failed auction occurs, the interest rate is set pursuant to a formula stipulated in the indenture.

The average annualized interest rates on the auction rate bonds follow:

Successor	Predecessor	
November 1, 2010 through December 31, 2010	January 1, 2010 through October 31, 2010	December 31, 2009
0.53%	0.51%	0.44%

The instruments governing this auction rate bond permit KU to convert the bond 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.

As a result of downgrades of the monoline insurers by all of the rating agencies to levels below that of the Company's rating, the debt ratings of the Company's insured bonds are all based on the Company's senior secured debt rating and are not influenced by the monoline bond insurer ratings.

In connection with the PPL acquisition, on November 1, 2010, KU borrowed $1,331 million from a PPL subsidiary, in order to repay loans from a subsidiary of E.ON. KU used the net proceeds received from the sale of the first mortgage bonds to repay the debt owed to the PPL subsidiary arising from the borrowing.

In November 2010, KU issued first mortgage bonds totaling $1,500 million and used the proceeds to repay the loans from a PPL subsidiary mentioned above and for general corporate purposes. The first mortgage bonds were issued at a discount as described in the table below:

First Mortgage Bonds	Principal	Discount Price	First Mortgage Bonds Proceeds (a)
Series due 2015	$ 250	99.650%	$ 249
Series due 2020	500	99.622%	498
Series due 2040	750	98.915%	742
Total	$ 1,500		$ 1,489

(a) Before expenses other than discount to Purchaser

The first mortgage bonds were issued by KU in accordance with the rules of Section 144A of the Securities Act of 1933. KU has entered into a registration rights agreement in which it has agreed to file a registration statement with the SEC relating to an offer to exchange the first mortgage bonds for publicly tradable securities having substantially identical terms. If ultimate registration and/or certain milestones are not completed by certain dates in mid- and late 2011, the Company has agreed to pay liquidated damages to the bondholders. The liquidated damages would total 0.25% per annum of the principal amount of the bonds for the first 90 days and 0.50% per annum of the principal amount thereafter until the conditions described above have been cured.

There were no redemptions or maturities of long-term debt for 2009. Redemptions and maturities of long-term debt for 2010 are summarized below:

Year	Description	Principal Amount	Rate	Secured/ Unsecured	Maturity
Successor					
2010	Due to PPL Investment Corp.	$ 1,331	4.24%-7.035%	Unsecured	2010-2037
2010	Due to E.ON affiliates	1,331	4.24%-7.035%	Unsecured	2010-2037

Issuances of long-term debt for 2010 and 2009 are summarized below:

Year	Description	Principal Amount	Rate	Secured/ Unsecured	Maturity
Successor					
2010	Due to PPL Investment Corp.	$ 1,331	4.24%-7.035%	Unsecured	2010-2037
2010	First mortgage bonds	250	1.625%	Secured	2015
2010	First mortgage bonds	500	3.25%	Secured	2020
2010	First mortgage bonds	750	5.125%	Secured	2040
Predecessor					
2009	Due to E.ON affiliates	50	4.445%	Unsecured	2019
2009	Due to E.ON affiliates	50	4.81%	Unsecured	2019
2009	Due to E.ON affiliates	50	5.28%	Unsecured	2017

As of December 31, 2010, all of the Company's long-term debt is secured by a first mortgage lien on substantially all of the real and tangible personal property of the Company located in Kentucky.

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

2011	$ -
2012	-
2013	-
2014	-
2015	250
Thereafter	1,601
	$ 1,851

KU was in compliance with all debt covenants at December 31, 2010.

See Note 1, Summary of Significant Accounting Policies, for certain debt refinancing and associated transactions completed by KU in connection with the PPL acquisition, Note 2, Acquisition by PPL, for the adjustment made to the pollution control bonds to reflect fair value and Note 15, Related Party Transactions, for long-term debt payable to affiliates.

Note 12 - Notes Payable and Other Short-Term Obligations

Intercompany Revolving Line of Credit

KU participates in an intercompany money pool agreement wherein LKE 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:

	Total Money Pool Available	Amount Outstanding	Balance Available	Average Interest Rate
December 31, 2010, Successor	$ 400	$ 10	$ 390	0.25%
December 31, 2009, Predecessor	400	45	355	0.20%

LKE maintains revolving credit facilities totaling $300 million at December 31, 2010 and $313 million at December 31, 2009, to ensure funding availability for the money pool. At December 31, 2010, the LKE facility is with PPL Investment Corp. LKE pays PPL Investment Corp. an annual commitment fee based on the Utilities' current bond ratings on the unused portion of the commitment. At December 31, 2009, one facility, totaling $150 million, was with E.ON North America, Inc., while the remaining line, totaling $163 million, was with Fidelia, both affiliated companies of E.ON. The balances are as follows:

	Total Available	Amount Outstanding	Balance Available	Average Interest Rate
December 31, 2010, Successor	$ 300	$ -	$ 300	N/A
December 31, 2009, Predecessor	313	276	37	1.25%

Bank Revolving Line of Credit

As of December 31, 2010, the Company maintained a $400 million revolving line of credit with a group of banks maturing in December 2014. The revolving line of credit allows KU to issue letters of credit or borrow funds up to $400 million. Outstanding letters of credit reduce the facility's available borrowing capacity. The Company pays the banks an annual commitment fee based on current bond ratings on the unused portion of the commitment. At December 31, 2010, there was no amount borrowed under this facility although letters of credit totaling $198 million have been issued under this facility. This credit agreement contains financial covenants requiring the borrower's debt to total capitalization ratio to not exceed 70%, as calculated pursuant to the credit agreement, and other customary covenants.

As of December 31, 2009, the Company maintained a $35 million bilateral line of credit with an unaffiliated financial institution maturing in June 2012. The Company paid the banks an annual commitment fee on the unused portion of the commitment. At December 31, 2009, there was no balance outstanding under this facility. This facility was terminated on November 1, 2010, in conjunction with the PPL acquisition.

On December 1, 2010, KU replaced the letters of credit issued under prior letter of credit facilities with letters of credit of the same amount issued under the revolving line of credit. The four letter of credit facilities were subsequently terminated.

KU was in compliance with all line of credit covenants at December 31, 2010.

See Note 1, Summary of Significant Accounting Policies, for certain debt refinancing and associated transactions completed by KU in connection with the PPL acquisition and Note 15, Related Party Transactions, for long-term debt payable to affiliates.

Note 13 - Commitments and Contingencies

Operating Leases

KU leases office space, office equipment, plant equipment, real estate, railcars, telecommunications 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 $10 million, $10 million and $9 million for 2010, 2009 and 2008, respectively. The future minimum annual lease payments for operating leases for years subsequent to December 31, 2010, are shown in the following table:

2011	$	8
2012		7
2013		5
2014		5
2015		3
Thereafter		1
	$	29

Owensboro Contract Litigation and Termination

In May 2004, the City of Owensboro, Kentucky and OMU commenced a suit against KU concerning a long-term power supply contract (the "OMU Agreement") with KU. In May 2009, KU and OMU executed a settlement agreement resolving the matter on a basis consistent with prior court rulings and KU has received the agreed settlement amounts. Pursuant to the settlement's operation, the OMU Agreement terminated in May 2010.

Sale and Leaseback Transaction

The Company 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. The Utilities 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 the Utilities had retained its ownership interest. The leasing transaction was entered into following receipt of required state and federal regulatory approvals. At December 31, 2010, the Balance Sheets included these assets at a value of $65 million, which is reflected in "Regulated utility plant – electric."

In case of default under the lease, the Company 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, 2010, the maximum aggregate amount of default fees or amounts was $7 million, of which KU would be responsible for 62% (approximately $4 million). The Company has made arrangements with LKE, via guarantee and regulatory commitment, for LKE to pay its full portion of any default fees or amounts.

Letters of Credit

KU has provided letters of credit as of December 31, 2010 and 2009, for on-balance sheet obligations totaling $198 million to support bonds of $195 million and letters of credit for off-balance sheet obligations totaling less than $1 million to support certain obligations related to workers' compensation.

Commodity Purchases

OVEC

KU has a contract for power purchases with OVEC, terminating in 2026, for various Mw capacities. KU holds a 2.5% investment interest in OVEC with ten other electric utilities. KU is not the primary beneficiary; therefore, the investment is not consolidated into the Company's financial statements, but is recorded on the cost basis. OVEC is located in Piketon, Ohio, and owns and operates two coal-fired power plants, Kyger Creek Station in Ohio, and Clifty Creek Station in Indiana. KU is contractually entitled to 2.5% of OVEC's output, approximately 60 Mw of nameplate generation capacity. Pursuant to the OVEC power purchase contract, the Company may be conditionally responsible for a 2.5% pro-rata share of certain obligations of OVEC under defined circumstances. These contingent liabilities may include unpaid OVEC indebtedness as well as shortfall amounts in certain excess decommissioning costs and postretirement benefits other than pension. KU's contingent potential proportionate share of OVEC's December 31, 2010 outstanding debt was $35 million. Future obligations for power purchases from OVEC are demand payments, comprised of annual minimum debt service payments, as well as contractually required reimbursement of plant operating, maintenance and other expenses, and are shown in the following table:

2011	$	9
2012		10
2013		10
2014		10
2015		10
Thereafter		114
	$	163

Coal and Natural Gas Transportation Purchase Obligations

KU has contracts to purchase coal and natural gas transportation. Future obligations are shown in the following table:

2011	$	439
2012		200
2013		144
2014		93
2015		91
Thereafter		14
	$	981

Construction Program

KU had approximately $116 million of commitments in connection with its construction program at December 31, 2010.

In June 2006, KU entered into a construction contract regarding the TC2 project. The contract is generally in the form of a 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. During 2009 and 2010, KU received several contractual notices from the TC2 construction contractor asserting historical force majeure and excusable event claims for a number of adjustments to the contract price, construction schedule, commercial operations date, liquidated damages or other relevant provisions. In September 2010, KU and the construction contractor agreed to a settlement to resolve the force majeure and excusable event claims occurring through July 2010, under the TC2 construction contract, which settlement provided for a limited, negotiated extension of the contractual commercial operations date and/or relief from liquidated damage calculations. With limited exceptions the Company took care, custody and control of TC2 on January 22, 2011, and has dispatched the unit to meet customer demand since that date. KU and the contractor agreed to a further amendment of the construction agreement whereby the contractor will complete certain actions relating to identifying and completing any necessary modifications to allow operation of TC2 on all fuels in accordance with initial specifications prior to certain dates, and amending the provisions relating to liquidated damages. KU cannot currently estimate the ultimate outcome of these matters.

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. In September 2007, the Secretary of the Kentucky Environmental and Public Protection Cabinet issued a final Order upholding the permit. The environmental groups petitioned the EPA to object to the state permit and subsequent permit revisions. In determinations made in September 2008 and June 2009, the EPA rejected most of the environmental groups' claims but identified three permit deficiencies which the KDAQ addressed by revising the permit. In August 2009, the EPA issued an Order denying the remaining claims with the exception of two additional deficiencies which the KDAQ was directed to address. The EPA determined that the proposed permit subsequently issued by the KDAQ satisfied the conditions of the EPA Order although the agency recommended certain enhancements to the administrative record. In January 2010, the KDAQ issued a final permit revision incorporating the proposed changes to address the two EPA objections. In March 2010, the Sierra Club submitted a petition to the EPA to object to the permit revision, which is now pending before the EPA. The Company believes that the final permit as revised should not have a material adverse effect on its financial condition or results of operations. However, until the EPA issues a final ruling on the pending petition and all applicable appeals have been exhausted, the Company cannot predict the final outcome of this matter.

Environmental Matters

The Company'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. As indicated below and summarized at the conclusion of this section, evolving environmental regulations will likely increase the level of capital and operating and maintenance expenditures incurred by the Company during the next several years. Based upon prior regulatory precedent, the Company believes that many costs of complying with such pending or future requirements would likely be recoverable under the ECR or other potential cost-recovery mechanisms, but the Company can provide no assurance as to the ultimate outcome of such proceedings before the regulatory authorities.

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.

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 place in the interim. The remand of the CAIR results in some uncertainty with respect to certain other EPA or state programs and proceedings and the Utilities' compliance plans relating thereto due to the interconnection of the CAIR with such associated programs.

In January 2010, the EPA proposed a revised NAAQS for ozone which would increase the stringency of the standard. In addition, the EPA published final revised NAAQS standards for NO_2 and SO_2 in February 2010 and June 2010, respectively, which are more stringent than previous standards. Depending on the level of action determined necessary to bring local nonattainment areas into compliance with the revised NAAQS standards, KU's power plants are potentially subject to requirements for additional reductions in SO_2 and NOx emissions.

In July 2010, the EPA issued the proposed CATR, which serves to replace the CAIR. The CATR provides for a two-phase SO_2 reduction program with Phase I reductions due by 2012 and Phase II reductions due by 2014. The CATR provides for NOx reductions in 2012, but the EPA advised that it is studying whether additional NOx reductions should be required for 2014. The CATR is more stringent than the CAIR as it accelerates certain compliance dates and provides for only intrastate and limited interstate trading of emission allowances. In addition to its preferred approach, the EPA is seeking comment on an alternative approach which would provide for individual emission limits at each power plant. The EPA has announced that it will propose additional "transport" rules to address compliance with revised NAAQS standards for ozone and particulate matter which will be issued by the EPA in the future, as discussed below.

Hazardous Air Pollutants

As provided in 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 entered into a consent decree requiring it to promulgate a utility Maximum Achievable Control Technology rule to replace the CAMR with a proposed rule due by March 2011 and a final rule by November 2011. Depending on the final outcome of the rulemaking, the CAMR could be replaced by new rules with different or more stringent requirements for reduction of mercury and other hazardous air pollutants. Kentucky has also repealed its corresponding state mercury regulations.

Acid Rain Program

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 Clean Air Act also contains 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 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 the 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 and continue to evaluate improvements to further reduce SO_2 emissions. 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. KU expects to incur additional capital expenditures currently approved in its ECR plans totaling approximately $500 million during the 2011 through 2013 time period to achieve emissions reductions and manage coal combustion residuals. Monthly recovery is subject to periodic review by the Kentucky Commission.

GHG Developments

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. As discussed below, 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, 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. The current administration has announced its support for the adoption of mandatory GHG reduction requirements at the federal level. The United States and other countries met in Copenhagen, Denmark, in December 2009, in an effort to negotiate a GHG reduction treaty to succeed the Kyoto Protocol, which is set to expire in 2013. In Copenhagen, the U.S. made a nonbinding commitment to, among other things, seek to reduce GHG emissions to 17% below 2005 levels by 2020 and provide financial support to developing countries. The United States and other nations met in Cancun, Mexico, in December 2010 to continue negotiations toward a binding agreement.

GHG Legislation

KU is monitoring on-going efforts to enact GHG reduction requirements and requirements governing carbon sequestration at the state and federal level and is assessing potential impacts of such programs and strategies to mitigate those impacts. In June 2009, the U.S. House of Representatives passed the American Clean Energy and Security Act of 2009, which was a comprehensive energy bill containing the first-ever nation-wide GHG cap and trade program. The bill provided for reductions in GHG emissions of 3% below 2005 levels by 2012, 17% by 2020 and 83% by 2050. In order to cushion potential rate impacts for utility customers, approximately 43% of emissions allowances would have initially been allocated at no cost to the electric utility sector, with this allocation gradually declining to 7% in 2029 and zero thereafter. The bill would have also established a renewable electricity standard requiring utilities to meet 20% of their electricity demand through renewable energy and energy efficiency by 2020. The bill contained additional provisions regarding carbon capture and sequestration, clean transportation, smart grid advancement, nuclear and advanced technologies and energy efficiency.

In September 2009, the Clean Energy Jobs and American Power Act, which was largely patterned on the House legislation, was introduced in the U.S. Senate. The Senate bill raised the emissions reduction target for 2020 to 20% below 2005 levels and did not include a renewable electricity standard. While the initial bill lacked detailed provisions for the allocation of emissions allowances, a subsequent revision incorporated allowance allocation provisions similar to the House bill. Although Senators Kerry and Lieberman and others worked to reach a consensus on GHG legislation, no bill passed the Senate in 2010. The Company is closely monitoring the progress of pending energy legislation, but the prospect for passage of comprehensive GHG legislation in 2011 is uncertain.

GHG Regulations

In April 2007, the U.S. Supreme Court ruled that the EPA has the authority to regulate GHG under the Clean Air Act. In April 2009, the EPA issued a proposed endangerment finding concluding that GHGs endanger public health and welfare, which is an initial rulemaking step under the Clean Air Act. A final endangerment finding was issued in December 2009. In September 2009, the EPA issued a final GHG reporting rule requiring reporting by facilities with annual GHG emissions equivalent to at least 25,000 tons of carbon dioxide. A number of the Company's facilities are required to submit annual reports commencing with calendar year 2010. In May 2010, the EPA issued a final GHG "tailoring" rule, effective January 2011, requiring new or modified sources with GHG emissions equivalent to at least 75,000 tons of carbon dioxide to obtain permits under the Prevention of Significant Deterioration Program. Such new or modified facilities would be required to install Best Available Control Technology. While the Company is unaware of any currently available GHG control technology that might be required for installation on new or modified power plants, it is currently assessing the potential impact of the rule. The final rule will apply to new and modified power plants beginning in January 2011. The Company is unable to predict whether mandatory GHG reduction requirements will ultimately be enacted through legislation or regulations. In December 2010, the EPA announced that it plans to promulgate GHG New Source Performance Standards for power plants, including both new and existing facilities. A proposed rule is expected by July 2011, while a final rule is expected by May 2012. In the absence of either a proposed or final regulation, KU is unable to assess the potential impact of any future regulation.

GHG Litigation

A number of lawsuits have been filed asserting common law claims including nuisance, trespass and negligence against various companies with GHG emitting facilities. In October 2009, a three judge panel of the United States Court of Appeals for the 5th Circuit in the case of Comer v. Murphy Oil reversed a lower court, holding that private plaintiffs have standing to assert certain common law claims against more than 30 utility, oil, coal and chemical companies. In March 2010, the court vacated the opinion of the three-judge panel and granted a motion for rehearing but subsequently denied the appeal due to the lack of a quorum. The appellate ruling leaves in effect the lower court ruling dismissing the plaintiffs' claims. In January 2011, the Supreme Court denied petitioner's petition for review, which effectively brings the case to an end. The Comer complaint alleged that GHG emissions from the defendants' facilities contributed to global warming which increased the intensity of Hurricane Katrina. E.ON, the former indirect parent of the Utilities, was named as a defendant in the complaint but was not a party to the proceedings due to the failure of the plaintiffs to pursue service under the applicable international procedures. KU continues to monitor relevant GHG litigation to identify judicial developments that may be potentially relevant to operations.

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. The Company is not able to estimate the outcome or potential effects of these matters, including whether substantial fines, penalties or remedial measures may result.

Ghent New Source Review NOV

In March 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 contends that the work in question, as pollution control projects, was exempt from the requirements cited by the EPA. In December 2009, the EPA issued a Section 114 information request seeking additional information on this matter. In March 2010, the Company received an EPA settlement proposal providing for imposition of additional permit limits and emission controls and anticipates continued settlement negotiations with the EPA. Negotiations between the EPA and KU are ongoing. Depending on the provisions of a final settlement or the results of litigation, if any, resolution of this matter could involve significant increased operating and capital expenditures. The Company is currently unable to determine the final outcome of this matter or the impact of an unfavorable determination on the Company's financial position or results of operations.

Ash Ponds and Coal-Combustion Byproducts

The EPA has undertaken various initiatives in response to the December 2008 impoundment failure at the TVA's Kingston power plant, which resulted in a major release of coal combustion byproducts into the environment. The EPA issued information requests to utilities throughout the country, including KU, to obtain information on their ash ponds and other impoundments. In addition, the EPA inspected a large number of impoundments located at power plants to determine their structural integrity. The inspections included several of KU's impoundments, which the EPA found to be in satisfactory condition. In June 2010, the EPA published proposed regulations for coal combustion byproducts handled in landfills and ash ponds. The EPA has proposed two alternatives: (1) regulation of coal combustion byproducts in landfills and ash ponds as a hazardous waste or (2) regulation of coal combustion byproducts as a solid waste with minimum national standards. Under both alternatives, the EPA has proposed safety requirements to address the structural integrity of ash ponds. In addition, the EPA will consider potential refinements of the provisions for beneficial reuse of coal combustion byproducts.

Water Discharges and PCB Regulations

The EPA has also announced plans to develop revised effluent limitation guidelines governing discharges from power plants and standards for cooling water intake structures. The EPA has further announced plans to develop revised standards governing the use of polychlorinated biphenyls ("PCB") in electrical equipment. The Company is monitoring these ongoing regulatory developments but will be unable to determine the impact until such time as new rules are finalized.

Impact of Pending and Future Environmental Developments

As a company with significant coal-fired generating assets, KU will likely be substantially impacted by pending or future environmental rules or legislation requiring mandatory reductions in GHG emissions or other air emissions, imposing more stringent standards on discharges to waterways, or establishing additional requirements for handling or disposal of coal combustion byproducts. These evolving environmental regulations will likely require an increased level of capital expenditures and increased incremental operating and maintenance costs by the Company over the next several years. Due to the uncertain nature of the final regulations that will ultimately be adopted by the EPA, including the reduction targets and the deadlines that will be applicable, the Company cannot finalize estimates of the potential compliance costs, but should the final rules incorporate additional emission reduction requirements, require more stringent emissions controls or implement more stringent byproducts storage and disposal practices, such costs will likely be significant. With respect to NAAQS, CATR, CAMR replacement and coal combustion byproducts developments, based upon a preliminary analysis of proposed regulations, the Company may be required to consider actions such as upgrading existing emissions controls, installing additional emissions controls, upgrading byproducts disposal and storage and possible early replacement of coal-fired units. Capital expenditures for KU associated with such actions are preliminarily estimated to be in the $1.5 to $1.7 billion range over the next ten years, although final costs may substantially vary. With respect to potential developments in water discharge, revised PCB standards or GHG initiatives, costs in such areas cannot be estimated due to the preliminary status or uncertain outcome of such developments, but would be in addition to the above amount and could be substantial. Ultimately, the precise impact on the Company's operations of these various environmental developments cannot be determined prior to the finalization of such requirements. Based upon prior regulatory precedent, the Company believes that many costs of complying with such pending or future requirements would likely be recoverable under the ECR or other potential cost-recovery mechanisms, but the Company can provide no assurance as to the ultimate outcome of such proceedings before the regulatory authorities.

TC2 Water Permit

In May 2010, the Kentucky Waterways Alliance and other environmental groups filed a petition with the Kentucky Energy and Environment Cabinet challenging the Kentucky Pollutant Discharge Elimination System permit issued in April 2010, which covers water discharges from the Trimble County generating station. In October 2010, the hearing officer issued a report and recommended Order providing for dismissal of the claims raised by the petitioners. In December 2010, the Secretary issued a final Order dismissing all claims and upholding the permit which petitioners subsequently appealed to Trimble County Circuit Court.

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 a prior Section 114 information request from the EPA relating to new-source review issues at KU's Ghent unit 2; completed settlement with state regulators regarding compliance with particulate limits in the air permit for KU's Tyrone generating station; remediation obligations or activities for or other risks relating to 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 on-going claims regarding the GHG emissions from the Company's generating stations. Based on analysis to date, the resolution of these matters is not expected to have a material impact on the Company's operations.

Note 14 - Jointly Owned Electric Utility Plant

TC2 is a jointly owned unit at the Trimble County site. KU and LG&E own undivided 60.75% and 14.25% interests, respectively. Of the remaining 25%, 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 is in-service. With limited exceptions the Company took care, custody and control of TC2 on January 22, 2011, and has dispatched the unit to meet customer demand since that date. KU and the contractor agreed to a further amendment of the construction agreement whereby the contractor will complete certain actions relating to identifying and completing any necessary modifications to allow operation of TC2 on all fuels in accordance with initial specifications prior to certain dates, and amending the provisions relating to liquidated damages. In December 2009 and June 2008, LG&E sold assets to KU related to the construction of TC2 with a net book value of $48 million and $10 million, respectively.

The following data represent shares of the jointly owned property (capacity based on nameplate rating):

	TC2				
	KU	LG&E	IMPA	IMEA	Total
Ownership interest	60.75%	14.25%	12.88%	12.12%	100%
Mw capacity	509	119	108	102	838

KU's 60.75% ownership:		LG&E's 14.25% ownership:	
Plant held for future use	$ 62	Plant held for future use	$ 2
Construction work in progress	703	Construction work in progress	187
Accumulated depreciation	(1)	Accumulated depreciation	-
Net book value	$ 764	Net book value	$ 189

KU and LG&E jointly own the following CTs and related equipment (capacity based on net summer capability) as of December 31, 2010:

	KU				LG&E				Total			
Ownership Percentage	Mw Capacity	Cost	Depr.	Net Book Value	Mw Capacity	Cost	Depr.	Net Book Value	Mw Capacity	Cost	Depr.	Net Book Value
KU 47%, LG&E 53% (a)	129	$ 43	$ -	$ 43	146	$ 48	$ -	$ 48	275	$ 91	$ -	$ 91
KU 62%, LG&E 38% (b)	190	64	(2)	62	118	40	(2)	38	308	104	(4)	100
KU 71%, LG&E 29% (c)	228	63	(1)	62	92	26	-	26	320	89	(1)	88
KU 63%, LG&E 37% (d)	404	109	(1)	108	236	64	(1)	63	640	173	(2)	171
KU 71%, LG&E 29% (e)	n/a	4	-	4	n/a	2	-	2	n/a	6	-	6

(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 each company's respective Statements of Income (i.e., fuel, maintenance of plant, other operating expense).

Note 15 - Related Party Transactions

KU and subsidiaries of LKE and PPL engage in related party transactions. Transactions between KU and LKE subsidiaries are eliminated on consolidation of LKE. Transactions between KU and PPL subsidiaries are eliminated on consolidation of PPL. These transactions are generally performed at cost and are in accordance with FERC regulations under PUHCA 2005 and the applicable Kentucky Commission and Virginia Commission regulations.

Intercompany Wholesale Sales and Purchases

KU and LG&E jointly dispatch their generation units with the lowest cost generation used to serve their retail native load. When LG&E has excess generation capacity after serving its own retail native load and its generation cost is lower than that of KU, KU purchases electricity from LG&E. When KU has excess generation capacity after serving its own retail native load and its generation cost is lower than that of LG&E, LG&E purchases electricity from KU. These transactions are recorded as intercompany wholesale sales and purchases are recorded by each company at a price equal to the seller's fuel cost. Savings realized from purchasing electricity intercompany instead of generating from their own higher costs units or purchasing from the market are shared equally between the Utilities. The volume of energy each company has to sell to the other is dependent on its native load needs and its available generation.

These sales and purchases are included in the Statements of Income as "Operating revenues", "Power purchased" expenses and "Other operation and maintenance expenses". KU's intercompany electric revenues and power purchased expenses were as follows:

	Successor	Predecessor		
	November 1, 2010 through December 31, 2010	January 1, 2010 through October 31, 2010	Year Ended December 31, 2009	Year Ended December 31, 2008
Electric operating revenues from LG&E	$ 2	$ 13	$ 21	$ 80
Power purchased and related operations and maintenance expenses from LG&E	21	79	101	109

Interest Charges

See Note 11, Long-Term Debt, and Note 12, 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 interest expense to affiliated companies was as follows:

	Successor	Predecessor		
	November 1, 2010 through December 31, 2010	January 1, 2010 through October 31, 2010	Year Ended December 31, 2009	Year Ended December 31, 2008
Interest on money pool loans	$ -	$ -	$ -	$ 2
Interest on PPL loans	2	-	-	-
Interest on Fidelia loans	-	62	69	56

Interest paid to LKE on the money pool arrangement was less than $1 million for 2010 and 2009.

Dividends

In September 2010, the Company paid dividends of $50 million to its sole shareholder, LKE.

Capital Contributions

The Company received no capital contributions in 2010, but received capital contributions of $75 million and $145 million from its sole shareholder, LKE, in 2009 and 2008, respectively.

Sale of Assets

In 2010, KU sold and bought assets of less than $1 million to and from LG&E. In December 2009, LG&E sold assets to KU related to the construction of TC2 with a net book value of $48 million.

Other Intercompany Billings

Servco provides the Company with a variety of centralized administrative, management and support services. Associated charges include payroll taxes paid by Servco on behalf of KU, labor and burdens of Servco employees performing services for KU, coal purchases and other vouchers paid by Servco on behalf of KU. The cost of these services is directly charged to the Company, 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/or other statistical information. These costs are charged on an actual cost basis.

In addition, the Utilities provide services to each other and to Servco. Billings between the Utilities relate to labor and overheads associated with union and hourly employees performing work for the other utility, charges related to jointly-owned generating units and other miscellaneous charges. Billings from KU to Servco include cash received by Servco on behalf of KU, tax settlements and other payments made by the Company on behalf of other non-regulated businesses which are reimbursed through Servco.

Intercompany billings to and from KU were as follows:

	Successor	Predecessor		
	November 1, 2010 through December 31, 2010	January 1, 2010 through October 31, 2010	Year Ended December 31, 2009	Year Ended December 31, 2008
Servco billings to KU	$ 46	$ 233	$ 169	$ 227
LG&E billings to KU	14	49	44	5
KU billings to Servco	12	11	14	3
KU billings to LG&E	-	-	78	75

Intercompany Balances

The Company had the following balances with its affiliates:

	Successor December 31, 2010	Predecessor December 31, 2009
Accounts receivable from LKE	$ 12	$ 9
Accounts payable to LG&E	22	53
Accounts payable to Servco	23	20
Accounts payable to Fidelia	-	15
Notes payable to LKE	10	45
Long-term debt to Fidelia	-	1,331

Note 16 - Selected Quarterly Data (Unaudited)

	For the 2010 Periods Ended (a)				
	Predecessor				Successor
	March 31	June 30	September 30	October 31	December 31
Operating revenues	$ 380	$ 350	$ 416	$ 102	$ 263
Operating income	87	71	105	22	65
Net income	44	31	54	11	35

(a) Periods ended March 31, June 30 and September 30 represent three months then ended. Period ended October 31 represents one month then ended and period ended December 31 represents two months then ended.

	For the 2009 Quarters Ended			
	Predecessor			
	March 31	June 30	September 30	December 31
Operating revenues	$ 363	$ 305	$ 341	$ 346
Operating income	19	53	125	72
Net income	7	26	66	34

Note 17 - Accumulated Other Comprehensive Income (Loss)

Accumulated other comprehensive income (loss) consisted of the following:

	Pre-Tax Accumulated Derivative Gain (Loss)	Income Taxes	Net
Balance at December 31, 2009, Predecessor	$ -	$ -	$ -
Equity investee's other comprehensive income (loss)	(3)	1	(2)
Balance at October 31, 2010, Predecessor	(3)	1	(2)
Effect of PPL acquisition	3	(1)	2
Balance at December 31, 2010, Successor	$ -	$ -	$ -

Note 18 - Subsequent Events

Subsequent events have been evaluated through February 25, 2011, the date of issuance of these statements. These statements contain all necessary adjustments and disclosures resulting from that evaluation.

On January 31, 2011, KU filed a notice of intent to file a rate case with the Virginia Commission for the test year ended December 31, 2010. The case is expected to be filed on or after April 1, 2011.

With limited exceptions the Company took care, custody and control of TC2 on January 22, 2011, and has dispatched the unit to meet customer demand since that date. LG&E and KU and the contractor agreed to a further amendment of the construction agreement whereby the contractor will complete certain actions relating to identifying and completing any necessary modifications to allow operation of TC2 on all fuels in accordance with initial specifications prior to certain dates, and amending the provisions relating to liquidated damages.

On January 14, 2011, KU contributed $43 million to its pension plan.

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Report of Independent Auditors

To Stockholder of Kentucky Utilities Company

In our opinion, the accompanying balance sheet and the related statements of income, retained earnings, comprehensive income, cash flows, and capitalization present fairly, in all material respects, the financial position of Kentucky Utilities Company (Successor Company) at December 31, 2010 and the results of its operations and its cash flows for the period from November 1, 2010 to December 31, 2010 in conformity with accounting principles generally accepted in the United States of America. Also in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2010, based on criteria established in *Internal Control - Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). The Company's management is responsible for these financial statements, for maintaining effective internal control over financial reporting and for its assertion of the effectiveness of internal control over financial reporting, included in "Management's Report of Internal Controls Over Financial Reporting" which appears on page 50. Our responsibility is to express opinions on these financial statements and on the Company's internal control over financial reporting based on our integrated audit. We conducted our audit in accordance with the standards of the Public Company Accounting Oversight Board (United States) and in accordance with the auditing and attestation standards established by the American Institute of Certified Public Accountants. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement and whether effective internal control over financial reporting was maintained in all material respects. Our audit of the financial statements included 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. Our audit of internal control over financial reporting included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audit also included performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinions.

As discussed in Note 2 to the financial statements, on November 1, 2010, PPL Corporation completed its acquisition of LG&E and KU Energy LLC and its subsidiaries. The push-down basis of accounting was used at the acquisition date.

A company's internal control over financial reporting is a process effected by those charged with governance, management, and other personnel, designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial

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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 (i) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (ii) 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 those charged with governance and (iii) provide reasonable assurance regarding prevention or timely detection and correction 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 and correct 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.

PricewaterhouseCoopers LLP

Louisville, Kentucky
February 25, 2011

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Report of Independent Auditors

To Stockholder of Kentucky Utilities Company

In our opinion, the accompanying balance sheet and the related statements of income, retained earnings, comprehensive income, cash flows, and capitalization present fairly, in all material respects, the financial position of Kentucky Utilities Company (Predecessor Company) at December 31, 2009 and the results of its operations and its cash flows for the period from January 1, 2010 to October 31, 2010 and for each of the two years in the period ended December 31, 2009 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 generally accepted auditing standards as established by the Auditing Standards Board (United States) and in accordance with the auditing standards of the Public Company Accounting Oversight Board (United States). 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, on November 1, 2010, PPL Corporation completed its acquisition of LG&E and KU Energy LLC and its subsidiaries. The push-down basis of accounting was used at the acquisition date.

PricewaterhouseCoopers LLP

Louisville, Kentucky
February 25, 2011

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LOUISVILLE GAS & ELECTIRC COMPANY
FINANCIAL STATEMENTS

MARCH 31, 2010

Louisville Gas and Electric Company

Financial Statements and Additional Information
(Unaudited)

As of March 31, 2010 and December 31, 2009
and for the three-month periods ended
March 31, 2010 and 2009

INDEX OF ABBREVIATIONS

AG	Attorney General of Kentucky
ARO	Asset Retirement Obligation
ASC	Accounting Standards Codification
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
CMRG	Carbon Management Research Group
Company	LG&E
DSM	Demand Side Management
ECR	Environmental Cost Recovery
EKPC	East Kentucky Power Cooperative, Inc.
E.ON	E.ON AG
E.ON U.S.	E.ON U.S. LLC
E.ON U.S. Services	E.ON U.S. Services Inc.
EPA	U.S. Environmental Protection Agency
FAC	Fuel Adjustment Clause
FASB	Financial Accounting Standards Board
FERC	Federal Energy Regulatory Commission
Fidelia	Fidelia Corporation (an E.ON affiliate)
GHG	Greenhouse Gas
GSC	Gas Supply Clause
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
LG&E	Louisville Gas and Electric Company
Mcf	Thousand Cubic Feet
MISO	Midwest Independent Transmission System Operator, Inc.
MMBtu	Million British thermal units
Moody's	Moody's Investors Service, Inc.
Mw	Megawatts
Mwh	Megawatt hours
NAAQS	National Ambient Air Quality Standards
NOx	Nitrogen Oxide
OCI	Other Comprehensive Income
RSG	Revenue Sufficiency Guarantee
REC	Renewable Energy Credits
S&P	Standard & Poor's Ratings Services
SIP	State Implementation Plan
SO_2	Sulfur Dioxide
TC1	Trimble County Unit 1
TC2	Trimble County Unit 2
VDT	Value Delivery Team Process
Virginia Commission	Virginia State Corporation Commission
WNA	Weather Normalization Adjustment

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PRICEWATERHOUSECOOPERS

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Report of Independent Accountants

To Shareholder of Louisville Gas and Electric Company:

We have reviewed the accompanying balance sheet of Louisville Gas and Electric Company as of March 31, 2010, and the related statements of income and retained earnings for the three-month periods ended March 31, 2010 and 2009 and the statements of cash flows for the three-month periods ended March 31, 2010 and 2009. This interim financial information is the responsibility of the Company's management.

We conducted our review in accordance with the standards established by the American Institute of Certified Public Accountants. A review of interim financial information consists principally of applying analytical procedures and making inquiries of persons responsible for financial and accounting matters. It is substantially less in scope than an audit conducted in accordance with auditing standards generally accepted in the United States of America, the objective of which is the expression of an opinion regarding the financial statements taken as a whole. Accordingly, we do not express such an opinion.

Based on our review, we are not aware of any material modifications that should be made to the accompanying interim financial information for it to be in conformity with accounting principles generally accepted in the United States of America.

We previously audited, in accordance with auditing standards generally accepted in the United States of America, the balance sheet of Louisville Gas and Electric Company as of December 31, 2009, and the related statements of income, retained earnings, and of cash flows for the year then ended (not presented herein), and in our report dated March 19, 2010, we expressed an unqualified opinion on those financial statements. In our opinion, the information set forth in the accompanying balance sheet as of December 31, 2009, is fairly stated in all material respects in relation to the balance sheet from which it has been derived.

PricewaterhouseCoopers LLP

May 14, 2010

Louisville Gas and Electric Company
Statements of Income
(Unaudited)
(Millions of $)

	Three Months Ended March 31, 2010	2009
Operating revenues		
Electric (Note 9)	$ 232	$ 235
Gas	134	193
Total operating revenues	366	428
Operating expenses		
Fuel for electric generation	83	91
Power purchased (Note 9)	17	19
Gas supply expenses	81	150
Other operation and maintenance expenses	87	123
Depreciation and amortization	34	33
Total operating expenses	302	416
Net operating income	64	12
Derivative loss (gain) (Note 3)	1	(5)
Other expense (income) – net (Note 3)	1	1
Interest expense (Notes 3 and 6)	4	4
Interest expense to affiliated companies (Notes 6 and 9)	7	7
Income before income taxes	51	5
Federal and state income tax expense (Note 5)	18	-
Net income	$ 33	$ 5

The accompanying notes are an integral part of these financial statements.

Statements of Retained Earnings
(Unaudited)
(Millions of $)

	Three Months Ended March 31, 2010	2009
Balance at beginning of period	$ 755	$ 740
Add net income	33	5
	788	745
Deduct cash dividends declared on common stock (Note 9).	30	35
Balance at end of period	$ 758	$ 710

The accompanying notes are an integral part of these financial statements

Louisville Gas and Electric Company
Balance Sheets
(Unaudited)
(Millions of $)

Assets	March 31, 2010	December 31, 2009
Current assets:		
Cash and cash equivalents	$ 5	$ 5
Accounts receivable, net:		
Customer – less reserves of $2 million as of March 31, 2010 and $1 million as December 31, 2009	127	131
Other – less reserves of $1 million as of March 31, 2010 and December 31, 2009, respectively	7	12
Accounts receivable from associated companies	16	53
Materials and supplies:		
Fuel (predominantly coal)	68	61
Gas stored underground	20	56
Other materials and supplies	34	33
Derivative asset (Note 3)	7	2
Deferred income taxes – net (Note 5)	4	4
Regulatory assets (Note 2)	13	14
Prepayments and other current assets	11	12
Total current assets	312	383
Utility plant:		
At original cost	4,226	4,200
Less: reserve for depreciation	1,722	1,708
Total utility plant, net	2,504	2,492
Construction work in progress	328	342
Total utility plant and construction work in progress	2,832	2,834
Deferred debits and other assets:		
Collateral deposit (Note 3)	15	17
Regulatory assets (Note 2):		
Pension and postretirement benefits	204	204
Other	126	125
Other assets	5	5
Total deferred debits and other assets	350	351
Total assets	$ 3,494	$ 3,568

The accompanying notes are an integral part of these financial statements.

Louisville Gas and Electric Company
Balance Sheets (cont.)
(Unaudited)
(Millions of $)

Liabilities and Equity	March 31, 2010	December 31, 2009
Current liabilities:		
Current portion of long-term debt (Notes 3 and 6)	$ 120	$ 120
Notes payable to affiliated company (Notes 6 and 9)	124	170
Accounts payable	89	97
Accounts payable to affiliated companies (Note 9)	39	28
Accrued income taxes	17	15
Customer deposits	24	22
Derivative liability (Note 3)	5	2
Regulatory liabilities (Note 2)	15	38
Other current liabilities	30	41
Total current liabilities	463	533
Long-term debt:		
Long-term bonds (Note 3 and 6)	291	291
Long-term debt to affiliated company (Notes 3, 6 and 9)	485	485
Total long-term debt	776	776
Deferred credits and other liabilities:		
Accumulated deferred income taxes (Note 5)	379	373
Accumulated provision for pensions and related benefits (Note 4)	183	198
Investment tax credit (Note 5)	47	48
Asset retirement obligations	32	31
Regulatory liabilities (Note 2):		
Accumulated cost of removal of utility plant	262	256
Deferred income taxes – net	38	41
MISO exit	3	3
Other	3	3
Customer advances for construction	8	8
Derivative liability (Note 3)	29	28
Other liabilities	16	17
Total deferred credits and other liabilities	1,000	1,006
Common equity:		
Common stock, without par value -		
Authorized 75,000,000 shares, outstanding 21,294,223 shares	424	424
Additional paid-in capital	84	84
Accumulated other comprehensive loss	(11)	(10)
Retained earnings (Note 9)	758	755
Total common equity	1,255	1,253
Total liabilities and equity	$ 3,494	$ 3,568

The accompanying notes are an integral part of these financial statements.

Louisville Gas and Electric Company
Statements of Cash Flows
(Unaudited)
(Millions of $)

	For the Three Months Ended March 31, 2010	2009
Cash flows from operating activities:		
Net income	$ 33	$ 5
Items not requiring cash currently:		
Depreciation and amortization	34	33
Deferred income taxes – net	3	1
Provision for pension and postretirement plans	7	9
Derivative liability	(2)	(11)
Changes in current assets and liabilities:		
Accounts receivable	(2)	34
Materials and supplies	27	79
Gas supply clause receivable – net	(26)	24
Accounts payable	11	(14)
Other current assets and liabilities	(10)	(13)
Change in collateral deposit – interest rate swap (Note 3)	2	5
Pension and postretirement funding (Note 4)	(21)	(2)
Other	4	2
Net cash provided by operating activities	60	152
Cash flows from investing activities:		
Construction expenditures	(31)	(43)
Assets sold to affiliate	48	-
Change in non-hedging derivatives	-	1
Net cash provided by (used for) investing activities	17	(42)
Cash flows from financing activities:		
Short-term borrowings from affiliated company – net (Note 6)	(47)	(74)
Payment of dividends (Note 9)	(30)	(35)
Net cash used for financing activities	(77)	(109)
Change in cash and cash equivalents	-	1
Cash and cash equivalents at beginning of period	5	4
Cash and cash equivalents at end of period	$ 5	$ 5

The accompanying notes are an integral part of these financial statements.

Louisville Gas and Electric Company
Statements of Comprehensive Income
(Unaudited)
(Millions of $)

	Three Months Ended March 31, 2010	Three Months Ended March 31, 2009
Net income	$ 33	$ 5
Gain (loss) on derivative instruments and hedging activities - net of tax (expense) benefit of less than $1 million and $(1) million, respectively (Note 3)	(1)	2
Comprehensive income	$ 32	$ 7

The accompanying notes are an integral part of these financial statements.

Note 1 - General

LG&E'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, comprehensive income 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 ("Annual Report") for the year ended December 31, 2009, including the audited financial statements and notes therein.

PPL Corporation ("PPL") Acquisition

On April 28, 2010, E.ON U.S. announced that E.ON AG and E.ON US Investments Corp. had entered into a definitive agreement with PPL, a Pennsylvania corporation, to sell to PPL all the equity interests of E.ON U.S. for a base purchase price, including the assumption of debt, totaling $7.625 billion. The transaction is anticipated to close by the end of 2010, subject to completion of all the conditions precedent to its consummation. These conditions include the approval of the Kentucky Commission, the Virginia Commission and the Tennessee Regulatory Authority under state utilities laws, the approval of the FERC under the Federal Power Act and the filing of required notices with the Department of Justice and the Federal Trade Commission under the Hart-Scott-Rodino Antitrust Improvements Act of 1976 and the application of relevant waiting periods.

Certain reclassification entries have been made to the previous years' financial statements to conform to the 2010 presentation with no impact on net assets, liabilities and capitalization or previously reported net income and net cash flows.

RECENT ACCOUNTING PRONOUNCEMENTS

Fair Value Measurements

In January 2010, the FASB issued guidance related to fair value measurement disclosures requiring separate disclosure of amounts of significant transfers in and out of level 1 and level 2 fair value measurements and separate information about purchases, sales, issuances and settlements within level 3 measurements. This guidance is effective for the first reporting period beginning after issuance except for disclosures about the roll-forward of activity in level 3 fair value measurements. This guidance has no impact on the Company's results of operations, financial position, liquidity or disclosures.

Note 2 - Rates and Regulatory Matters

For a description of each line item of regulatory assets and liabilities and for descriptions of certain matters which may not have undergone material changes relating to the period covered by this quarterly report, reference is made to Note 2 of LG&E's Annual Report for the year ended December 31, 2009.

2010 Electric and Gas Rate Cases

In January 2010, LG&E filed an application with the Kentucky Commission requesting an increase in electric base rates of approximately 12%, or $95 million annually, and its gas base rates of approximately 8%, or $23 million annually, including an 11.5% return on equity for electric and gas. LG&E requested the increase, based on the twelve month test year ended October 31, 2009, to become effective on and after March 1, 2010. The requested rates have been suspended until August 1, 2010, at which time they may be put into effect, subject to refund, if the Kentucky Commission has not issued an order in the proceeding. The parties are currently exchanging data requests and other filings in the proceedings and a hearing date has been scheduled for June 2010. A number of intervenors have entered the rate case, including the Kentucky Attorney General's office, certain representatives of industrial and low-income groups and other third parties, and submitted filings challenging the Companies' requested rate increases, in whole or in part. An order in the proceeding may occur during the third or fourth quarters of 2010.

2008 Electric and Gas Rate Cases

In January 2009, LG&E, the AG, KIUC and all other parties to electric and gas base rate cases filed a settlement agreement with the Kentucky Commission. Under the terms of the settlement agreement, LG&E's base gas rates increased $22 million annually, and base electric rates decreased $13 million annually. An Order approving the settlement was received in February 2009, and the new rates were implemented effective February 6, 2009. In connection with the application and effective date of the new rates, the VDT surcredit and merger surcredit terminated, resulting in increased revenues of approximately $21 million annually.

Regulatory Assets and Liabilities

The following regulatory assets and liabilities were included in LG&E's Balance Sheets:

(in millions)	March 31, 2010	December 31, 2009
Current regulatory assets:		
GSC	$ 4	$ 3
ECR	4	7
FAC	2	-
MISO exit	1	1
Other	2	3
Total current regulatory assets	$ 13	$ 14

	March 31, 2010	December 31, 2010
Non-current regulatory assets:		
Storm restoration	$ 67	$ 67
ARO	30	30
Unamortized loss on bonds	22	22
MISO exit	4	4
Other	3	2
Subtotal non-current regulatory assets	126	125
Pension benefits	204	204
Total non-current regulatory assets	$ 330	$ 329
Current regulatory liabilities:		
GSC	$ 10	$ 34
DSM	5	4
Total current regulatory liabilities	$ 15	$ 38
Non-current regulatory liabilities:		
Accumulated cost of removal of utility plant	$ 262	$ 256
Deferred income taxes – net	38	41
MISO exit	3	3
Other	3	3
Total non-current regulatory liabilities	$ 306	$ 303

LG&E does not currently earn a rate of return on the ECR, FAC, GSC and gas performance-based ratemaking (included in "GSC" above) regulatory assets which are separate recovery mechanisms with recovery within twelve months. No return is earned on the pension benefits regulatory asset that represents the changes in funded status of the plans. LG&E will recover this asset through pension expense included in the calculation of base rates. No return is currently earned on the ARO asset. When an asset with an ARO is retired, the related ARO regulatory asset will be offset against the associated ARO regulatory liability, ARO asset and ARO liability. A return is earned on the unamortized loss on bonds, and these costs are recovered through amortization over the life of the debt. LG&E currently earns a rate of return on the balance of Mill Creek Ash Pond costs included in other regulatory assets, as well as recovery of these costs. The Company is seeking recovery of the storm restoration regulatory asset and adjustments to the amortization of CMRG and KCCS contributions, included in other regulatory assets, in the current base rate case. The Company recovers through the calculation of base rates, the amortization of the net MISO exit regulatory asset incurred through April 30, 2008, and other regulatory assets including the East Kentucky Power Cooperative FERC transmission settlement agreement and rate case expenses. Other regulatory liabilities include DSM and MISO administrative charges collected via base rates from May 2008 through February 5, 2009. The MISO regulatory liability will be netted against the remaining costs of withdrawing from the MISO, per a Kentucky Commission Order, in the current Kentucky base rate case.

ECR. In January 2010, the Kentucky Commission initiated a six-month review of LG&E's environmental surcharge for the billing period ending October 2009. An order is anticipated in the second quarter of 2010.

In June 2009, the Company filed an application for a new ECR plan with the Kentucky Commission seeking approval to recover investments in environmental upgrades and operations and maintenance costs at the Company's generating facilities. During 2009, LG&E reached a unanimous settlement with all parties to the case and the Kentucky Commission issued an Order approving LG&E's application. Recovery on customer bills through the monthly ECR surcharge for these projects began with the February 2010 billing cycle.

FAC. In January 2010, the Kentucky Commission initiated a six-month review of LG&E's FAC mechanism for the expense period ended August 2009. An order is anticipated in the second quarter of 2010.

Other Regulatory Matters

Kentucky Commission Report on Storms. In November 2009, the Kentucky Commission issued a report following review and analysis of the effects and utility response to the September 2008 wind storm and the January 2009 ice storm, and possible utility industry preventative measures relating thereto. The report suggested a number of proposed or recommended preventative or responsive measures, including consideration of selective hardening of facilities, altered vegetation management programs, enhanced customer outage communications and similar measures. In March 2010, the Companies filed a joint response reporting on their actions with respect to such recommendations. The response indicated implementation or completion of substantially all of the recommendations, including, among other matters, on-going reviews of system hardening and vegetation management procedures, certain test or pilot programs and implementation of enhanced operational and customer outage-related systems.

Wind Power Agreements. In August 2009, LG&E and KU filed a notice of intent with the Kentucky Commission indicating their intent to file an application for approval of wind power purchase contracts and cost recovery mechanisms. The contracts were executed in August 2009, and were contingent upon LG&E and KU receiving acceptable regulatory approvals. Pursuant to the proposed 20-year contracts, LG&E and KU would jointly purchase respective assigned portions of the output of two Illinois wind farms totaling an aggregate 109.5 Mw. In September 2009, the Companies filed an application and supporting testimony with the Kentucky Commission. In October 2009, the Kentucky Commission issued an Order denying the Companies' request to establish a surcharge for recovery of the costs of purchasing wind power. The Kentucky Commission stated that such recovery constitutes a general rate adjustment and is subject to the regulations of a base rate case. The Kentucky Commission Order provided for the request for approval of the wind power agreements to proceed independently from the request to recover the costs thereof via surcharges. In November 2009, LG&E and KU filed for rehearing of the Kentucky Commission's Order and requested that the matters of approval of the contract and recovery of the costs thereof remain the subject of the same proceeding. During December 2009, the Kentucky Commission issued data requests on this matter.

In March 2010, LG&E and KU delivered notices of termination under provisions of the wind power contracts. The Companies also filed a motion with the Kentucky Commission noting the termination of the contracts and seeking withdrawal of their application in the related regulatory proceeding. In April 2010, the Kentucky Commission issued an Order allowing the Companies to withdraw their pending application.

Trimble County Asset Transfer and Depreciation. LG&E and KU are currently constructing a new base-load, coal fired unit, TC2, which will be jointly owned by the Companies, together with the IMEA and the IMPA. In July 2009, the Companies notified the Kentucky Commission of the proposed sale from LG&E to KU of certain ownership interests in certain existing Trimble County generating station assets which are anticipated to provide joint or common use in support of the jointly-owned TC2 generating unit under construction at the station. The undivided ownership interests being sold are intended to provide KU an ownership interest in these common assets that is proportional to its interest in TC2 and the assets' role in supporting both TC1 and TC2. In December 2009, LG&E and KU completed the sale transaction at a price of $48 million, representing the current net book value of the assets, multiplied by the proportional interest being sold.

In August 2009, in a separate proceeding, LG&E and KU jointly filed an application with the Kentucky Commission to approve new depreciation rates for applicable TC2-related generating, pollution control and other plant equipment and assets. The filing requests common depreciation rates for the applicable jointly-owned TC2-related assets, rather than applying differing depreciation rates in place with respect to LG&E's and KU's separately-owned base-load generating assets. During December 2009, the Kentucky Commission extended the data discovery process through January 2010, and authorized LG&E and KU on an interim basis to begin using the depreciation rates for TC2 as proposed in the application. In March 2010, the Kentucky Commission issued a final Order approving the use of the proposed depreciation rates on a permanent basis.

TC2 CCN Application and Transmission Matters. An application for a CCN for construction of TC2 was approved by the Kentucky Commission in November 2005. CCNs for two transmission lines associated with TC2 were issued 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 property owners in Hardin County, Kentucky. In August 2006, LG&E and KU 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. A motion for discretionary review of that reversal was filed by LG&E and KU with the Kentucky Supreme Court and was granted in April 2009. That proceeding, which seeks reinstatement of the Circuit Court dismissal of the CCN challenge, has been fully briefed and oral argument occurred during March 2010. A ruling on the matter could occur by mid 2010.

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 the transmission line in some of these forums as well.

During 2008, LG&E's affiliate, KU obtained various successful rulings at the Hardin County Circuit Court confirming its condemnation rights. In August 2008, several landowners appealed such rulings to the Kentucky Court of Appeals and received a temporary stay preventing KU from accessing their properties. In April 2009, that appellate court denied KU's motion to lift the stay and issued an Order retaining the stay until a decision on the merits of the appeal. Efforts to seek reconsideration of that ruling, or to obtain intermediate review of the ruling by the Kentucky Supreme Court, were unsuccessful, and the stay remains in effect. In April 2010, the

Kentucky Court of Appeals issued an Order affirming the Hardin Circuit Court's finding that KU had the right to condemn easements on the properties, which appellate Order remains subject to certain reconsideration or appeals rights of the parties.

Settlement discussions with the Hardin County property owners involved in the appeals of the condemnation proceedings have been unsuccessful to date. During the fourth quarter of 2008, LG&E and KU entered into settlements with certain Meade County landowners and obtained dismissals of prior litigation they had brought challenging the same transmission line.

As a result of the aforementioned unresolved litigation delays encountered in obtaining access to certain properties in Hardin County, KU has obtained easements to allow construction of temporary transmission facilities bypassing those properties while the litigated issues are resolved. In September 2009, the Kentucky Commission issued an Order stating that a CCN was necessary for two segments of the proposed temporary facilities. In December 2009, the Kentucky Commission granted the CCNs for the relevant segments and the property owners have filed various motions to intervene, stay and appeal certain elements of the Kentucky Commission's recent orders. In January 2010, in respect of two of such proceedings, the Franklin County circuit court issued Orders denying the property owners' request for a stay of construction and upholding the prior Kentucky Commission denial of their intervenor status. In parallel with, and consistent with the relevant legal proceedings and their status, KU is proceeding with the construction activities with respect to these temporary transmission facilities.

In a separate proceeding, certain Hardin County landowners have also challenged the same transmission line in federal district court in Louisville, Kentucky. In that action, the landowners claim that the U.S. Army failed to comply with certain National Historic Preservation Act requirements relating to easements for the line through Fort Knox. LG&E and KU are cooperating with the U.S. Army in its defense in this case and in October 2009, the federal court granted the defendants' motion for summary judgment and dismissed the plaintiffs' claims. During November 2009, the petitioners filed submissions for review of the decision with the 6th Circuit Court of Appeals.

LG&E and KU are not currently able to predict the ultimate outcome and possible effects, if any, on the construction schedule relating to the transmission line approval, land acquisition and permitting proceedings.

Market-Based Rate Authority. In July 2006, the FERC issued an Order in LG&E's market-based rate proceeding accepting the Company'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 LG&E of power at market-based rates in the LG&E/KU 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 the Company'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. As a condition of receiving and retaining market-based rate authority, LG&E must comply with applicable affiliate restrictions set forth in the FERC regulation. During

September 2008, the Company submitted a regular tri-annual update filing under market-based rate regulations.

In June 2009, the FERC issued Order No. 697-C which generally clarified certain interpretations relating to power sales and purchases at control area interfaces or into control areas involving market power. In July 2009, the FERC issued an order approving the Company's September 2008 application for market-based rate authority. During July 2009, affiliates of LG&E completed a transaction terminating certain prior generation and power marketing activities in the Big Rivers Electric Corporation control area, which termination should ultimately allow a filing to request a determination that the Company no longer is deemed to have market power in such control area.

LG&E conducts certain of its wholesale power sales activities in accordance with existing market-based rate authority principles and interpretations. Future FERC proceedings relating to Orders 697 or market-based rate authority could alter the amount of sales made at market-based versus cost-based rates. The Company's sales under market-based rate authority totaled $10 million for the three months ended March 31, 2010.

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 Regional Reliability Organizations ("RROs") by the North American Electric Reliability Corporation ("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. LG&E and KU are members of the SERC Reliability Corporation ("SERC"), which acts as LG&E's and KU's RRO. During December 2009, the SERC and LG&E and KU agreed to settlements involving penalties totaling less than $1 million for each utility related to their self-reports during June and October 2008, concerning possible violations of standards. During December 2009 and April 2010, LG&E and KU submitted self-reports relating to additional standards, the resolution of which the Companies do not anticipate will result in material penalties or remedial actions, but which processes remain in the early stages and therefore the Companies are unable to determine the outcome. 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. While LG&E and KU believe they are in compliance with the mandatory reliability standards, they cannot predict the outcome of other analyses, including on-going SERC or other reviews described above.

Green Energy Riders. In May 2007, a Kentucky Commission Order was issued authorizing LG&E to establish Small and Large Green Energy Riders, allowing customers to contribute funds to be used for the purchase of renewable energy credits ("REC") through June 1, 2010. During November 2009, LG&E and KU filed an application to both continue and modify the existing Green Energy Programs. In February 2010, the Kentucky Commission approved the Companies' application, as filed.

Note 3 - Financial Instruments

The cost and estimated fair values of LG&E's non-trading financial instruments as of March 31, 2010 and December 31, 2009 follows:

	March 31, 2010		December 31, 2009	
(in millions)	Carrying Value	Fair Value	Carrying Value	Fair Value
Long-term debt (including current portion of $120 million)	$ 411	$ 417	$ 411	$ 411
Long-term debt from affiliate	$ 485	$ 515	$ 485	$ 512
Interest-rate swaps – liability	$ 29	$ 29	$ 28	$ 28

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 LG&E's credit ratings and default risk. The fair values of the swaps reflect price quotes from dealers, consistent with the Fair Value Measurements and Disclosures topic of the FASB ASC. The fair values of cash and cash equivalents, accounts receivable, accounts payable and notes payable are substantially the same as their carrying values.

LG&E is subject to the risk of fluctuating interest rates in the normal course of business. The Company's policies allow for the interest rate risk to be managed through the use of fixed rate debt, floating rate debt and interest rate swaps. At March 31, 2010, a 100 basis point change in the benchmark rate on LG&E's variable rate debt, not effectively hedged by an interest rate swap, would impact pre-tax interest expense by $2 million annually.

The Company is subject to interest rate and commodity price risk related to on-going business operations. It currently manages these risks using derivative financial instruments, including swaps and forward contracts.

LG&E has classified the applicable financial assets and liabilities that are accounted for at fair value into the three levels of the fair value hierarchy, as defined by the Fair Value Measurements and Disclosures topic of the FASB ASC, as follows:

- Level 1 - Observable inputs that reflect quoted prices (unadjusted) for identical assets or liabilities in active markets.
- Level 2 - Include other inputs that are directly or indirectly observable in the marketplace.
- Level 3 - Unobservable inputs which are supported by little or no market activity.

Interest Rate Swaps. LG&E uses 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 is intended to mitigate risk, earnings and cash flow volatility and is not speculative in nature.

The fair value of the interest rate swaps is determined by a quote from the counterparty. This value is verified monthly by the Company using a model that calculates the present value of future payments under the swap utilizing current swap market rates obtained from another dealer active in the swap market and validated by market transactions. Market liquidity is considered, however the valuation does not require an adjustment for market liquidity as the market is very active for the type of swaps used by the Company. LG&E considered the impact of counterparty credit risk by evaluating credit ratings and financial information. All counterparties had strong investment grade ratings at March 31, 2010. LG&E did not have any credit exposure to the swap counterparties, as it was in a liability position at March 31, 2010, therefore, the market valuation required no adjustment for counterparty credit risk. In addition, the Company and the counterparties have agreed to post margin if the credit exposure exceeds certain thresholds. Using these valuation methodologies, the swap contracts are considered level 2 based on measurement criteria in the Fair Value Measurements and Disclosures topic of the FASB ASC. Cash collateral for interest rate swaps is classified as a long-term asset and is a level 1 measurement based on the funds being held in a demand deposit account.

LG&E was party to various interest rate swap agreements with aggregate notional amounts of $179 million as of March 31, 2010 and December 31, 2009. Under these swap agreements, LG&E paid fixed rates averaging 4.52% and received variable rates based on LIBOR or the Securities Industry and Financial Markets Association's municipal swap index averaging 0.19% and 0.20% at March 31, 2010 and December 31, 2009, respectively. One swap hedging the Company's $83 million Trimble County 2000 Series A bond has been designated as a cash flow hedge and continues to be highly effective.

The interest rate swaps are accounted for on a mark-to-market basis in accordance with the Derivatives and Hedging topic of the FASB ASC. Financial instruments designated as effective cash flow hedges have resulting gains and losses recorded within other comprehensive income and common equity. The ineffective portion of financial instruments designated as cash flow hedges is recorded to earnings monthly as is the entire change in the market value of the ineffective swaps. For the three month periods ended March 31, 2010 and 2009, LG&E recorded a pre-tax loss of less than $1 million and a pre-tax gain of less than $1 million in interest expense, respectively, to reflect the change in the ineffective portion of the interest rate swaps deemed highly effective. For the three months ended March 31, 2010, LG&E recorded a pre-tax loss of less than $1 million in derivative loss (gain) for the change in the mark-to-market value of the ineffective interest rate swaps. The table below shows the pre-tax amount and income statement location of gains from interest rate swaps for the three months ended March 31, 2009:

(in millions) March 31, 2009	Location of Gain Recognized in Income on Derivatives	Amount of Gain Recognized in Income on Derivatives
Interest rate swaps – change in the mark-to-market of ineffective swaps	Derivative loss (gain)	$ (6)
Total		$ (6)

Amounts recorded in accumulated other comprehensive income will be reclassified into earnings in the same period during which the hedged forecasted transaction affects earnings. The amount amortized from other comprehensive income to income in the three month period ended March

31, 2010, was less than $1 million. The amount expected to be reclassified from other comprehensive income to earnings in the next twelve months is less than $1 million.

A decline of 100 basis points in the current market interest rates would reduce the fair value of LG&E's interest rate swaps by approximately $28 million. Such a change could affect other comprehensive income if the hedge is effective, or the income statement if the hedge is ineffective.

Energy Trading and Risk Management Activities. LG&E 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 the Derivatives and Hedging topic of the FASB ASC.

Energy trading and risk management contracts are valued using prices based on active trades from Intercontinental Exchange Inc. In the absence of a traded price, midpoints of the best bids and offers are the primary determinants of valuation. When sufficient trading activity is unavailable, other inputs 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 measurement criteria in the Fair Value Measurements and Disclosures topic of the FASB ASC. 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 2010 or 2009. Changes in market pricing, interest rate and volatility assumptions were made during both years.

The Company maintains credit policies intended to minimize credit risk in wholesale marketing and trading activities by assessing the creditworthiness of potential counterparties prior to entering into transactions with them and continuing to evaluate their creditworthiness once transactions have been initiated. To further mitigate credit risk, LG&E seeks to enter into netting agreements or require cash deposits, letters of credit and parental company guarantees as security from counterparties. The Company uses S&P, Moody's and definitive qualitative and quantitative data to assess the financial strength of counterparties on an on-going basis. If no external rating exists, LG&E assigns an internally generated rating for which it sets appropriate risk parameters. As risk management contracts are valued based on changes in market prices of the related commodities, credit exposures are revalued and monitored on a daily basis. At March 31, 2010, 100% of the trading and risk management commitments were with counterparties rated BBB-/Baa3 equivalent or better. The Company 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 March 31, 2010 and December 31, 2009, counterparty credit reserves related to the energy trading and risk management contracts were less than $1 million.

The net volume of electricity-based financial derivatives outstanding at March 31, 2010 and December 31, 2009, was zero Mwhs and 587,800 Mwhs, respectively. No cash collateral related to the energy trading and risk management contracts was required at March 31, 2010. Cash collateral at December 31, 2009, is categorized as other accounts receivable and is a level 1 measurement based on the funds being held in liquid accounts.

The following tables set forth by level within the fair value hierarchy, LG&E's financial assets and liabilities that were accounted for at fair value on a recurring basis as of March 31, 2010 and December 31, 2009. There are no level 3 measurements for the periods ending March 31, 2010 and December 31, 2009.

Recurring Fair Value Measurements (in millions)
March 31, 2010

	Level 1	Level 2	Total
Financial assets:			
Energy trading and risk management contracts	$ -	$ 7	$ 7
Interest rate swap cash collateral	15	-	15
Total financial assets	$ 15	$ 7	$ 22
Financial liabilities:			
Energy trading and risk management contracts	$ -	$ 5	$ 5
Interest rate swaps	-	29	29
Total financial liabilities	$ -	$ 34	$ 34

Recurring Fair Value Measurements (in millions)
December 31, 2009

	Level 1	Level 2	Total
Financial assets:			
Energy trading and risk management contract cash collateral	$ 2	$ -	$ 2
Energy trading and risk management contracts	-	2	2
Interest rate swap cash collateral	17	-	17
Total financial assets	$ 19	$ 2	$ 21
Financial liabilities:			
Energy trading and risk management contracts	$ -	$ 2	$ 2
Interest rate swaps	-	28	28
Total financial liabilities	$ -	$ 30	$ 30

The Company does not net collateral against derivative instruments.

Certain of the Company's derivative instruments contain provisions that require the Company to provide immediate and on-going collateralization on derivative instruments in net liability positions based upon the Company's credit ratings from each of the major credit rating agencies. At March 31, 2010, there are no energy trading and risk management contracts with credit risk related contingent features that are in a liability position, and no collateral posted in the normal course of business. The aggregate mark-to-market value of all interest rate swaps with credit risk related contingent features that are in a liability position on March 31, 2010, is $22 million, for which the Company has posted collateral of $15 million in the normal course of business. If the credit risk related contingent features underlying these agreements were triggered on March 31, 2010, due to a one notch downgrade in the Company's credit rating, the Company would be required to post an additional $4 million of collateral to its counterparties for the interest rate swaps and there would be no effect on the energy trading and risk management contracts or collateral required as a result of these contracts.

The tables below show the fair value and balance sheet location of derivatives designated as hedging instruments as of March 31, 2010 and December 31, 2009:

March 31, 2010 (in millions)	Asset Derivatives Balance Sheet Location	Fair Value	Liability Derivatives Balance Sheet Location	Fair Value
Interest rate swaps	Other assets	$ -	Long-term derivative liability	$ 19
Total		$ -		$ 19

December 31, 2009 (in millions)	Asset Derivatives Balance Sheet Location	Fair Value	Liability Derivatives Balance Sheet Location	Fair Value
Interest rate swaps	Other assets	$ -	Long-term derivative liability	$ 19
Total		$ -		$ 19

The tables below show the fair value and balance sheet location of derivatives not designated as hedging instruments as of March 31, 2010 and December 31, 2009:

March 31, 2010 (in millions)	Asset Derivatives Balance Sheet Location	Fair Value	Liability Derivatives Balance Sheet Location	Fair Value
Interest rate swaps	Other assets	$ -	Long-term derivative liability	$ 10
Energy trading and risk management contracts	Other current assets	7	Other current liabilities	5
Total		$ 7		$ 15

December 31, 2009 (in millions)	Asset Derivatives Balance Sheet Location	Fair Value	Liability Derivatives Balance Sheet Location	Fair Value
Interest rate swaps	Other assets	$ -	Long-term derivative liability	$ 9
Energy trading and risk management contracts	Other current assets	2	Other current liabilities	2
Total		$ 2		$ 11

The gain (loss) on hedging interest rate swaps recognized in OCI for the three month period ended March 31, 2010, was $(1) million. For the three month period ended March 31, 2010, the gain on derivatives reclassified from accumulated OCI to income was less than $1 million, and was recorded in other income (expense) – net.

LG&E manages the price risk of its estimated future excess economic generation capacity using market-traded forward contracts. Hedge accounting treatment has not been elected for these transactions, and therefore gains and losses are shown in the statements of income.

The following table presents the effect of derivatives not designated as hedging instruments on income for the three months ended March 31:

(in millions)	Location of Gain (Loss) Recognized in Income on Derivatives	Amount of Gain (Loss) Recognized in Income on Derivatives	
		Three Months Ended March 31, 2010	Three Months Ended March 31, 2009
Energy trading and risk management contracts (realized)	Electric revenues	$ 1	$ 1
Energy trading and risk management contracts (unrealized)	Electric revenues	2	2
Interest rate swaps (realized)	Derivative loss (gain)	1	1
Interest rate swaps (unrealized)	Derivative loss (gain)	-	(6)
Total		$ 4	$ (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 for the three months ended March 31. The tables include the costs associated with both LG&E employees and E.ON U.S. Services employees who are providing services to the Company. The E.ON U.S. Services costs that are allocated to LG&E are approximately 43% and 44% of E.ON U.S. Services costs for March 31, 2010 and 2009, respectively.

Pension Benefits
Three Months Ended March 31,

(in millions)	2010 LG&E	2010 E.ON U.S. Services Allocation to LG&E	2010 Total LG&E	2009 LG&E	2009 E.ON U.S. Services Allocation to LG&E	2009 Total LG&E
Service cost	$ 1	$ 1	$ 2	$ 1	$ 1	$ 2
Interest cost	6	2	8	7	2	9
Expected return on plan assets	(6)	(1)	(7)	(6)	(1)	(7)
Amortization of prior service costs	1	-	1	1	-	1
Amortization of actuarial loss	3	-	3	3	-	3
Benefit cost	$ 5	$ 2	$ 7	$ 6	$ 2	$ 8

Other Postretirement Benefits
Three Months Ended March 31,

(in millions)	2010 LG&E	2010 E.ON U.S. Services Allocation to LG&E	2010 Total LG&E	2009 LG&E	2009 E.ON U.S. Services Allocation to LG&E	2009 Total LG&E
Service cost	$ -	$ -	$ -	$ -	$ 1	$ 1
Interest cost	1	-	1	1	-	1
Amortization of prior service costs	1	-	1	1	-	1
Benefit cost	$ 2	$ -	$ 2	$ 2	$ 1	$ 3

In January 2010, LG&E made a contribution to a pension plan covering its employees of $20 million. In addition, E.ON U.S. Services made a pension plan contribution of $9 million. LG&E's intent is to fund the pension plan in a manner consistent with the requirements of the Pension Protection Act of 2006.

In 2010, LG&E has made contributions to other postretirement benefit plans totaling $1 million. The Company also anticipates further funding to match the annual postretirement expense and funding the 401(h) plan up to the maximum amount allowed by law.

Note 5 - 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 LG&E, 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. The Company also files income tax returns in various state jurisdictions. While the federal statute of limitations related to 2006 and later years are open under the federal statute of limitations, Revenue Agent Reports for

2006-2007 have been received from the IRS, effectively closing these years to additional audit adjustments. Adjustments to these tax years were previously recorded in the financial statements. Tax years 2007 and 2008 were 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. Adjustments for 2007, agreed to and recorded in January 2009, were comprised of $5 million of depreciation-related differences. Areas remaining under examination for 2008 include bonus depreciation and the Company's application for a change in repair deductions. No net material adverse impact is expected from these remaining areas.

Additions and reductions of uncertain tax positions during 2010 and 2009 were less than $1 million. Possible amounts of uncertain tax positions for LG&E 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. If recognized, the less than $1 million of unrecognized tax benefits would reduce the effective income tax rate.

The amount LG&E recognized as interest expense and interest accrued related to unrecognized tax benefits was less than $1 million as of March 31, 2010 and December 31, 2009. The interest expense and interest accrued is based on IRS and Kentucky Department of Revenue large corporate interest rates for underpayment of taxes. At the date of adoption, the Company accrued less than $1 million in interest expense on uncertain tax positions. LG&E records the interest as interest expense and penalties as operating expenses in the income statement and accrued expenses in the balance sheet, on a pre-tax basis. No penalties were accrued by the Company through March 31, 2010.

In June 2006, LG&E and KU 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 LG&E and KU 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, LG&E received an Order from the Kentucky Commission approving the accounting of the investment tax credit. LG&E's portion of the TC2 tax credit will be approximately $24 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, LG&E recorded investment tax credits of $1 million during the three months ended March 31, 2009, decreasing current federal income taxes. The amount claimed through 2009 is all that LG&E is allowed to claim. LG&E has recorded its maximum credit of $24 million. In addition, a full depreciation basis adjustment is required for the amount of the credit. The income tax expense impact from amortizing these credits 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. During 2008 and 2009, the plaintiffs submitted amended complaints alleging additional claims for relief. In October 2009, the plaintiffs filed a motion for a preliminary injunction seeking temporary implementation of certain elements of the requested relief. The Company 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

LG&E's long-term debt includes $120 million of pollution control bonds that are 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 Jefferson County 2001 Series A and B and Trimble County 2001 Series A and B. Maturity dates for these bonds range from 2026 to 2027. The average annualized interest rate for these bonds during the three months ended March 31, 2010 was 0.69%.

Pollution control bonds are obligations of LG&E issued in connection with tax-exempt pollution control revenue bonds issued by various governmental entities, principally counties in Kentucky. A loan agreement obligates the Company to make debt service payments to the governmental entities that equate to the debt service due from the entity on the related pollution control revenue bonds. The loan agreement is an unsecured obligation of the Company.

Several of the LG&E pollution control bonds are insured by monoline bond insurers whose ratings have been reduced due to exposures relating to insurance of sub-prime mortgages. At March 31, 2010, LG&E had an aggregate $574 million (including $163 million of reacquired bonds) of outstanding pollution control indebtedness, of which $135 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. During 2008, interest rates increased, and the Company experienced "failed auctions" when there were insufficient bids for the bonds. When a failed auction occurs, the interest rate is set pursuant to a formula stipulated in the indenture. During the three months ended March 31, 2010 and 2009, the average rate on the auction rate bonds was 0.27% and 0.47%, respectively. The instruments governing these auction rate bonds permit LG&E 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 June 2009, S&P downgraded the credit rating of Ambac, an insurer of the Company's bonds, from "A" to "BBB". As a result, S&P downgraded the ratings on the Trimble County 2000 Series A, 2002 Series A and 2007 Series A; Jefferson County 2001 Series A and Louisville Metro 2007 Series B bonds from "A" to "BBB+" in June 2009. The S&P ratings of these bonds are now based on the rating of the Company rather than the rating of Ambac since the Company's rating is higher.

During 2008, LG&E converted several series of its pollution control bonds from the auction rate mode to a weekly interest rate mode, as permitted under the loan documents. In connection with these conversions, the Company purchased the bonds from the remarketing agent. As of March 31, 2010, the Company continued to hold repurchased bonds in the amount of $163 million. The other repurchased bonds were remarketed during 2008 in an intermediate-term fixed rate mode wherein the interest rate is reset periodically (every three to five years). LG&E will hold some or all of such repurchased bonds until a later date, at which time it may refinance, remarket or further convert such bonds. Uncertainty in markets relating to auction rate securities or steps the Company has taken or may take to mitigate such uncertainty, such as additional conversion, subsequent restructuring or redemption and refinancing, could result in increased interest expense, transaction expenses or other costs and fees or experiencing reduced liquidity relating to existing or future pollution control financing structures.

The Company participates in an intercompany money pool agreement wherein E.ON U.S. and/or KU make funds available to LG&E 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
March 31, 2010	$ 400	$ 124	$ 276	.21%
December 31, 2009	$ 400	$ 170	$ 230	.20%

E.ON U.S. maintains revolving credit facilities totaling $313 million at March 31, 2010 and December 31, 2009, to ensure funding availability for the money pool. At March 31, 2010, 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 balances are as follows:

($ in millions)	Total Available	Amount Outstanding	Balance Available	Average Interest Rate
March 31, 2010	$ 313	$ 164	$ 149	1.47%
December 31, 2009	$ 313	$ 276	$ 37	1.25%

As of March 31, 2010, the Company maintained bilateral lines of credit, with unaffiliated financial institutions, totaling $125 million which mature in June 2012. At March 31, 2010, there was no balance outstanding under any of these facilities.
There were no redemptions or issuances of long-term debt year-to-date through March 31, 2010.

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 the Company's Annual Report for the year ended December 31, 2009 (including, but not limited to Notes 2, 9 and 14 to the financial statements of LG&E contained therein). See the Company's Annual Report regarding such commitments or contingencies.

Construction Program. LG&E had approximately $50 million of commitments in connection with its construction program at March 31, 2010.

In June 2006, LG&E and KU 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. In March 2009, the parties completed an agreement resolving certain 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. The Company's share of additional costs from inception of the contract through the expected project completion in 2010 is estimated to be approximately $10 million. During the past and to date in 2010, LG&E and KU have received a number of contractual notices from the TC2 construction contractor asserting force majeure/excusable event claims for additional adjustments to either or both of contract price or construction schedule with respect to certain events which, if granted, may affect such contractual terms in addition to a possible extension of the commercial operations date, liquidated damages or other relevant provisions. The parties are continuing to discuss such matters in good faith and are attempting to resolve them in a commercially reasonable manner. The Company cannot currently estimate the ultimate outcome of these matters, including the extent, if any, that may result in increased costs charged for construction of TC2 and/or relief relating to the construction completion or operations dates.

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. In September 2007, the Secretary of the Kentucky Environmental and Public Protection Cabinet issued a final Order upholding the permit. The environmental groups petitioned the EPA to object to the state permit and subsequent permit revisions. In determinations made in September 2008 and June 2009, the EPA rejected most of the environmental groups' claims, but identified three permit deficiencies which the KDAQ addressed by revising the permit. In August 2009, the EPA issued an order denying the remaining claims with the exception of two additional deficiencies which the KDAQ was directed to address. The EPA determined that the proposed permit subsequently issued by the KDAQ satisfied the conditions of the EPA Order, although the agency recommended certain enhancements to the administrative record. In January 2010, the KDAQ issued a final permit revision incorporating the proposed changes to address the EPA objections. In March 2010, the environmental groups submitted a petition to the EPA to object to the permit revision, which petition is now pending before the EPA. The Company believes that the final permit as revised should not have a material adverse effect on its financial condition or results of operations. However, until the EPA issues a final ruling on the pending petition and all appeals have been exhausted, the Company cannot predict the final outcome of this matter.

Thermostat Replacement. During January 2010, LG&E and KU announced a voluntary plan to replace certain thermostats which had been provided to customers as part of the Companies' demand reduction programs, due to concerns that the thermostats may present a safety hazard. Under the plan, the Companies anticipate replacing up to approximately 14,000 thermostats. Estimated costs associated with the replacement program may be $2 million. However, the Companies cannot fully predict the ultimate outcome of the replacement program or other effects or developments which may be associated with the thermostat replacement matter at this time.

Environmental Matters. The Company's operations are subject to a number of environmental laws and regulations, 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 LG&E'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 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, LG&E's power plants are potentially subject to additional reductions in SO_2 and NOx emissions. In January 2010, EPA issued a proposed rule to reconsider the NAAQS for Ozone, previously revised in 2008. The proposal would institute more stringent standards. At present, the Company 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 place 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. LG&E 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 the Companies' compliance plans relating thereto, due to the interconnection of the CAIR with such associated programs. At present, LG&E 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 Clean Air Act, as amended, 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 Clean Air Mercury Rule ("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 addition, in 2006, the Metro Louisville Air Pollution Control District adopted rules aimed at regulating additional hazardous air pollutants from sources including power plants.

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 rules with different or more stringent requirements for reduction of mercury and other hazardous air pollutants. Kentucky has also repealed its corresponding state mercury regulations. At present, LG&E 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 Clean Air Act, as amended, 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 Clean Air Act, as amended, also contains 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 ("CAVR") detailing how the Clean Air Act's Best Available Retrofit Technology ("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. LG&E had previously installed flue gas desulfurization equipment on all of its generating units prior to the effective date of the acid rain program. LG&E's strategy for its Phase II SO_2 requirements, which commenced in 2000, is to use accumulated emission allowances to defer additional capital expenditures and LG&E will continue to evaluate improvements to further reduce SO_2 emissions. In order to achieve the NOx emission reductions mandated by the NOx SIP Call, LG&E installed additional NOx controls, including selective catalytic reduction technology, during the 2000 through 2009 time period at a cost of $197 million. In 2001, the Kentucky Commission granted approval to recover the costs incurred by LG&E for these projects through the environmental surcharge mechanisms. Such monthly recovery is subject to periodic review by the Kentucky Commission.

In order to achieve mandated emissions reductions, LG&E expects to incur additional capital expenditures totaling approximately $85 million during the 2010 through 2012 time period for pollution control 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. LG&E believes its costs in reducing SO_2, NOx and mercury emissions to be comparable to those of similarly situated utilities with like generation assets. LG&E'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. LG&E 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.

GHG Developments. 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. As discussed below, 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. The current administration has announced its support for the adoption of mandatory GHG reduction requirements at the federal level. The United States and other countries met in Copenhagen, Denmark in December 2009, in an effort to negotiate a GHG reduction treaty to succeed the Kyoto Protocol, which is set to expire in 2013. At Copenhagen, the U.S. made a nonbinding commitment to, among other things, seek to reduce GHG emissions to 17% below 2005 levels by 2020 and provide financial support to developing countries. The United States and other nations are scheduled to meet in Cancun, Mexico in late 2010 to continue negotiations toward a binding agreement.

GHG Legislation. LG&E is monitoring on-going efforts to enact GHG reduction requirements and requirements governing carbon sequestration at the state and federal level and is assessing potential impacts of such programs and strategies to mitigate those impacts. In June 2009, the U.S. House of Representatives passed the American Clean Energy and Security Act of 2009, (H.R. 2454), which is a comprehensive energy bill containing the first-ever nation-wide GHG cap and trade program. The bill would provide for reductions in GHG emissions of 3% below 2005 levels by 2012, 17% by 2020, and 83% by 2050. In order to cushion potential rate impacts for utility customers, approximately 43% of emissions allowances would initially be allocated at no cost to the electric utility sector, with this allocation gradually declining to 7% in 2029 and zero thereafter. The bill would also establish a renewable electricity standard requiring utilities to meet 20% of their electricity demand through renewable energy and energy efficiency by 2020. The bill contains additional provisions regarding carbon capture and sequestration, clean transportation, smart grid advancement, nuclear and advanced technologies and energy efficiency.

In September 2009, the Clean Energy Jobs and American Power Act (S. 1733), which is largely patterned on the House legislation, was introduced in the U.S. Senate. The Senate bill raises the emissions reduction target for 2020 to 20% below 2005 levels and does not include a renewable electricity standard. While the initial bill lacked detailed provisions for the allocation of emissions allowances, a subsequent revision incorporated allowance allocation provisions similar to the House bill. More recently, Senators Kerry, Lieberman and others have announced that they are currently working on GHG legislation covering the utility and transportation sectors that would provide for a 17% reduction in GHG emissions by 2020, but have introduced no bill in the Senate to date. The Company is closely monitoring the progress of the legislation, although the prospect for passage of comprehensive GHG legislation in 2010 is uncertain.

GHG Regulations In April 2007, the U.S. Supreme Court ruled that the EPA has the authority to regulate GHG under the Clean Air Act. In April 2009, the EPA issued a proposed endangerment finding concluding that GHGs endanger public health and welfare, which is an initial rulemaking step under the Clean Air Act. A final endangerment finding was issued in December 2009. In September 2009, the EPA issued a final GHG reporting rule requiring reporting by facilities with annual GHG emissions equivalent to at least 25,000 tons of carbon dioxide. A number of the Company's facilities will be required to submit annual reports commencing with calendar year 2010. Also in September 2009, the EPA proposed the GHG "tailoring" rule requiring new or modified sources with GHG emissions equivalent to at least 10,000 to 25,000 tons of carbon dioxide to obtain permits under the Prevention of Significant Deterioration Program. Such new or modified facilities would be required to install Best Available Control Technology. While the Company is unaware of any currently available GHG control technology that might be required for installation on new or modified power plants, it is currently assessing the potential impact of the proposed rule. A final tailoring rule is expected in 2010. The EPA has announced that the final tailoring rule will address the phase in of GHG regulation for these stationary sources and will provide for regulation of new or modified stationary sources such as power plants in 2011. The Company is unable to predict whether mandatory GHG reduction requirements will ultimately be enacted through legislation or regulations. As a company with significant coal-fired generating assets, LG&E could be substantially impacted by programs requiring mandatory reductions in GHG emissions, although the precise impact on its operations, including the reduction targets and deadlines that would be applicable, cannot be determined prior to the enactment of such programs. While the Company believes that many costs of complying with mandatory GHG reduction requirements or purchasing emission allowances to meet applicable requirements would likely be recoverable, in whole or in part under the ECR, where such costs are related to the Company's coal-fired generating assets, or other potential cost-recovery mechanisms, this cannot be assured.

GHG Litigation. A number of lawsuits have been filed asserting common law claims including nuisance, trespass and negligence against various companies with GHG emitting facilities. In October 2009, a three judge panel of the United States Court of Appeals for the 5th Circuit in the case of Comer v. Murphy Oil reversed a lower court, holding that private plaintiffs have standing to assert certain common law claims against more than 30 utility, oil, coal and chemical companies. However, in March 2010, the court vacated the opinion of the three-judge panel and granted a motion for rehearing. The Comer complaint alleges that GHG emissions from the defendants' facilities contributed to global warming which increased the intensity of Hurricane Katrina. E.ON, the parent of LG&E and KU was included as defendant in the complaint, but has not been subject to the proceedings due to the failure of the plaintiffs to pursue service under the applicable international procedures. LG&E and KU are currently unable to predict further developments in the Comer case. LG&E and KU continue to monitor relevant GHG litigation to identify judicial developments that may be potentially relevant to their operations.

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 TC1 generating units and KU's Ghent 2 generating unit. LG&E and KU have complied with the information requests and are not able to predict further proceedings in this matter at this time.

Ash Ponds, Coal-Combustion Byproducts and Water Discharges. The EPA has undertaken various initiatives in response to the December 2008 impoundment failure at the Tennessee Valley Authority's Kingston power plant, which resulted in a major release of coal combustion byproducts into the environment. The EPA issued information requests to utilities throughout the country, including LG&E, to obtain information on their ash ponds and other impoundments. In addition, the EPA inspected a large number of impoundments located at power plants to determine their structural integrity. The inspections included several of the Company's impoundments, which the EPA found to be in satisfactory condition except for certain impoundments at the Mill Creek and Cane Run stations, which were determined to be in fair condition. In May 2010, the EPA announced proposed regulations for coal combustion byproducts handled in landfills and ash ponds. The EPA has proposed two alternatives: (1) regulation of coal combustion byproducts in landfills and ash ponds as a hazardous waste; or (2) regulation of coal combustion byproducts as a solid waste with minimum national standards. Under both alternatives, the EPA has proposed safety requirements to address the structural integrity of ash ponds. In addition, the EPA will consider potential refinements of the provisions for beneficial reuse of coal combustion byproducts. The EPA has also announced plans to develop revised effluent limitations guidelines and standards governing discharges from power plants. The Company is monitoring these ongoing regulatory developments, but will be unable to determine the impact until such time as new rules are finalized.
In May 2010, the Sierra Club and other environmental groups filed a petition with the Kentucky Energy and Environment Cabinet challenging the Kentucky Pollutant Discharge Elimination System permit issued in April 2010, which covers water discharges from the Trimble County Station. Due to the preliminary stage of the proceedings, the Company is currently unable to predict the outcome or precise impact of this matter.

General Environmental Proceedings. From time to time, LG&E 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 obligations or activities for former manufactured gas plant sites or elevated Polychlorinated Biphenyl levels at existing properties; liability under the Comprehensive Environmental Response, Compensation and Liability Act for cleanup at various off-site waste sites; on-going claims regarding alleged particulate emissions from the Company's Cane Run station and claims regarding GHG emissions from the Company's generating stations. With respect to the former manufactured gas plant sites, LG&E has estimated that it could incur additional costs of less than $1 million for remaining clean-up activities under existing approved plans or agreements. Based on analysis to date, the resolution of these matters is not expected to have a material impact on the Company's operations.

Note 8 - Segments of Business

LG&E's revenues, net income and total assets by business segment for the three months ended March 31, were as follows:

(in millions)	2010	2009
LG&E Electric		
Revenues	$ 232	$ 235
Net income	16	(6)
Total assets	2,831	2,780
LG&E Gas		
Revenues	134	193
Net income	17	11
Total assets	663	730
Total		
Revenues	366	428
Net income	33	5
Total assets	3,494	3,510

Note 9 - Related Party Transactions

LG&E, subsidiaries of E.ON U.S. and subsidiaries of E.ON engage in related party transactions. Transactions between LG&E and E.ON U.S. subsidiaries are eliminated upon consolidation of E.ON U.S. Transactions between LG&E and E.ON subsidiaries are eliminated upon consolidation of E.ON. These transactions are generally performed at cost and are in accordance with FERC regulations under the Public Utility Holding Company Act of 2005 and the applicable Kentucky Commission regulations. The significant related party transactions are disclosed as follows.

Electric Purchases

LG&E and KU 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 electric operating revenues and purchased power operating expense. LG&E's intercompany electric revenues and purchased power expense for the three months ended March 31, were as follows:

(in millions)	2010	2009
Electric operating revenues from KU	$ 24	$ 31
Purchased power from KU	7	9

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.

LG&E's intercompany interest expense for the three months ended March 31, was as follows:

(in millions)	2010	2009
Interest on Fidelia loans	$ 7	$ 7

Other Intercompany Billings

E.ON U.S. Services provides the Company 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 LG&E, labor and burdens of E.ON U.S. Services employees performing services for LG&E, coal purchases and other vouchers paid by E.ON U.S. Services on behalf of LG&E. The cost of these services is directly charged to the Company, 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, LG&E and KU provide services to each other and to E.ON U.S. Services. Billings between LG&E and KU relate to labor and overheads associated with union and hourly employees performing work for the other utility, charges related to jointly-owned generating units and other miscellaneous charges. Billings from LG&E to E.ON U.S. Services include cash received by E.ON U.S. Services on behalf of LG&E, primarily tax settlements, and other payments made by the Company on behalf of other non-regulated businesses which are reimbursed through E.ON U.S. Services.

Intercompany billings to and from LG&E for the three months ended March 31, were as follows:

(in millions)	2010	2009
E.ON U.S. Services billings to LG&E	$ 56	$ 43
LG&E billings to KU	8	-
KU billings to LG&E	-	11
LG&E billings to E.ON U.S. Services	5	-

In March 2010, the Company paid dividends of $30 million to its common shareholder, E.ON U.S.

Note 10 - Subsequent Events

Subsequent events have been evaluated through May 14, 2010, the date of issuance of these statements and these statements contain all necessary adjustments and disclosures resulting from that evaluation.

On April 28, 2010, E.ON U.S. announced that E.ON AG and E.ON US Investments Corp. had entered into a definitive agreement with PPL, a Pennsylvania corporation, to sell to PPL all the equity interests of E.ON U.S. for a base purchase price, including the assumption of debt, totaling $7.625 billion. The transaction is anticipated to close by the end of 2010, subject to completion of all the conditions precedent to its consummation. In connection with the announcement, Moody's placed the debt ratings of the Company under review for possible downgrade. S&P affirmed the existing ratings of the Company. See Note 1, General.

On April 9, 2010, the Kentucky Commission issued an Order allowing the Companies to withdraw their pending application for approval of the wind power contracts.

Management's Discussion and Analysis

General

The following discussion and analysis by management focuses on those factors that had a material effect on LG&E's financial results of operations and financial condition during the three month period ended March 31, 2010, 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, 2009.

Executive Summary

Business

LG&E, incorporated in Kentucky in 1913, is a regulated public utility engaged in the generation, transmission, distribution and sale of electric energy and the storage, distribution and sale of natural gas. LG&E provides electric service to approximately 397,000 customers in Louisville and adjacent areas in Kentucky covering approximately 700 square miles in 9 counties. Natural gas service is provided to approximately 322,000 customers in its electric service area and 8 additional counties in Kentucky. Approximately 97% of the electricity generated by LG&E is produced by its coal-fired electric generating stations, all equipped with systems to reduce SO_2 emissions. The remainder is generated by a hydroelectric power plant and natural gas and oil fueled combustion turbines. Underground natural gas storage fields help LG&E provide economical and reliable natural gas service to customers.

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

PPL Acquisition

On April 28, 2010, E.ON U.S. announced that E.ON AG and E.ON US Investments Corp. had entered into a definitive agreement with PPL, a Pennsylvania corporation, to sell to PPL all the equity interests of E.ON U.S. for a base purchase price, including the assumption of debt, totaling $7.625 billion. The transaction is anticipated to close by the end of 2010, subject to completion of all the conditions precedent to its consummation. These conditions include the approval of the Kentucky Commission, the Virginia Commission and the Tennessee Regulatory Authority under state utilities laws, the approval of the FERC under the Federal Power Act and the filing of required notices with the Department of Justice and the Federal Trade Commission under the Hart-Scott-Rodino Antitrust Improvements Act of 1976 and the application of relevant waiting periods.

Regulatory Matters

In January 2010, LG&E filed an application with the Kentucky Commission requesting an increase in electric base rates of approximately 12%, or $95 million annually, and its gas base rates of approximately 8%, or $23 million annually, including an 11.5% return on equity for electric and gas. LG&E requested the increase, based on the twelve month test year ended October 31, 2009, to become effective on and after March 1, 2010. The requested rates have been suspended until August 1, 2010, at which time they may be put into effect, subject to refund, if the Kentucky Commission has not issued an order in the proceeding. The parties, including a number of intervenors, are currently exchanging data requests and other filings in the proceedings and a hearing date has been scheduled for June 2010. An order in the proceeding may occur during the third or fourth quarters of 2010.

In January 2009, LG&E, the AG, KIUC and all other parties to electric and gas base rate cases filed a settlement agreement with the Kentucky Commission. Under the terms of the settlement agreement, the Company's base gas rates increased $22 million annually, and base electric rates decreased $13 million annually. An Order approving the settlement was received in February 2009, and the new rates were implemented effective February 6, 2009. In connection with the application and effective date of the new rates, the VDT surcredit and merger surcredit terminated, resulting in increased revenues of approximately $21 million annually.

In January 2009, a significant winter ice storm passed through LG&E's service territory causing approximately 205,000 customer outages, followed closely by a severe wind storm in February 2009, causing approximately 37,000 customer outages. LG&E incurred $44 million of incremental operation and maintenance expenses and $10 million of capital expenditures related to the restoration following the two storms. The Company filed an application with the Kentucky Commission in April 2009, requesting approval to establish a regulatory asset, and defer for future recovery, approximately $45 million in incremental operation and maintenance expenses related to the storm restoration. In September 2009, the Kentucky Commission issued an Order allowing the Company to establish a regulatory asset of up to $45 million based on its actual costs for storm damages and service restoration due to the January and February 2009 winter storms. In September 2009, the Company established a regulatory asset of $44 million for actual costs incurred, and the Company is seeking recovery of this asset in its current base rate case.

Environmental Matters

General. Protection of the environment is a major priority for LG&E and a significant element of its business activities. LG&E's properties and operations are subject to extensive environmental-related oversight by federal, state and local regulatory agencies, including via air quality, water quality, waste management and similar laws and regulations. Therefore, LG&E must conduct its operations in accordance with numerous permit and other requirements issued under or contained in such laws or regulations.

Climate Change. Recent developments continue to indicate an increased possibility of significant climate change or GHG legislation or regulation, at the international, federal, regional and state levels. During December 2009, as part of the United Nation's Copenhagen Accord, the United States agreed to a non-binding goal to reduce GHG emissions to 17% below 2005 levels by 2020. Additionally, during 2009, the U.S. House of Representatives passed a comprehensive GHG legislation, which included a number of measures to limit GHG emissions and achieve GHG emission reduction targets below 2005 levels of 3%, 17% and 83% by 2012, 2020 and 2050, respectively, and the U.S. Senate is considering companion legislation. In late 2009, the EPA issued or proposed various regulatory initiatives relating to GHG matters, including an endangerment finding relating to mobile sources of GHGs, a GHG reporting requirement and a proposed rule relating to permitting requirements for new or modified GHG emission sources. Finally, a number of U.S. states, although not currently including Kentucky, have adopted GHG-reduction legislation or regulation of various sorts. The developing GHG initiatives include a number of differing structures and formats, including direct limitations on GHG sources, issuance of allowances for GHG emissions, cap-and-trade programs for such allowances, renewable or alternative generation portfolio standards and mechanisms relating to demand reduction, energy efficiency, smart-grid, transmission expansion, carbon-sequestration or other GHG-reducing efforts. While the final terms and impacts of such initiatives cannot be estimated, LG&E, as a primarily coal-fired utility, could be highly affected by such proceedings.

The cost to LG&E and the effect on LG&E's business of complying with potential GHG restrictions will depend upon the details of the programs ultimately enacted. Some of the design elements which may have the greatest effect on LG&E include (a) the required levels and timing of any carbon caps or limits, (b) the emission sources covered by such caps or limits, (c) transition and mitigation provisions, such as phase-in periods, free allowances or price caps, (d) the availability and pricing of relevant GHG-reduction technologies, goods or services and (e) economic, market and customer reaction to electricity price and demand changes due to GHG limits.

Ultimately, environmental matters or potential environmental matters can represent an important element of current or future potential capital requirements, future unit retirement or replacement decisions, supply and demand for electricity, operating and maintenance expenses or compliance risks for the Company. While LG&E currently anticipates that many of such direct costs or effects may be recoverable through rates or other regulatory mechanisms, particularly with respect to coal-related generation, the availability, timing or completeness of such rate recovery cannot be assured. Ultimately, climate change matters could result in material effects on LG&E's results of operations, liquidity and financial position. See Management's Discussion and Analysis and Note 7 of Notes to Financial Statements for additional information.

Results of Operations

The electric and gas 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 March 31, 2010, Compared to
Three Months Ended March 31, 2009

Net Income

Net income for the three months ended March 31, 2010, increased $28 million compared to the same period in 2009. The increase was primarily the result of decreased operating expenses ($114 million), partially offset by decreased operating revenues ($62 million), increased income taxes ($18 million) and increased derivative loss (gain) ($6 million).

Revenues

Electric revenues decreased $3 million in the three months ended March 31, 2010, primarily due to:

- Decreased wholesale sales ($10 million) due to:
  - Decreased sales volumes to KU ($6 million) primarily due to coal-fired generation unit outages during the first quarter of 2010. Via a mutual agreement, LG&E sells its lower cost electricity to KU to serve KU's native load and purchases KU's excess economic capacity to make wholesale sales
  - Decreased sales volumes with third-parties ($3 million) primarily due to increased energy demand from industrial and residential customers and due to coal-fired generation unit outages during the first quarter of 2010
  - Decreased sales to KU ($1 million) due to lower cost of fuel resulting in lower pricing
- Decreased revenues from base rates ($2 million) due to lower base energy non-fuel rates charged to customers during the period
- Decreased fuel costs billed to customers through the FAC ($2 million) due to lower fuel prices

Partially offset by:

- Increased retail sales volumes delivered ($8 million) due to increased consumption by residential customers as a result of colder weather and higher usage by commercial and industrial customers as a result of improved economic conditions, in addition to the colder weather
- Increased DSM revenue ($3 million) due to increased recoverable program spending
- Increased miscellaneous electric operating revenue ($1 million) primarily due to increased late payment charges

Natural gas revenues decreased $59 million in the three months ended March 31, 2010, primarily due to:

- Decreased average cost of gas billed to retail customers through the GSC ($86 million) due to reductions in gas prices as a result of lower fuel costs
- Decreased WNA revenues ($5 million) due to higher retail sales volumes resulting from increased total heating degree days

Partially offset by:

- Increased retail sales volumes delivered ($25 million) due to higher consumption by residential customers as a result of colder weather, and increased usage by commercial and industrial customers as a result of improved economic conditions, in addition to the colder weather
- Increased retail revenues from base rates ($5 million) due to the full period benefit of higher base rates resulting from the application of the base rate case settlement in February 2009
- Increased DSM revenue ($1 million) due to increased recoverable program spending

Expenses

Fuel for electric generation and natural gas supply expense comprise a large component of total operating expenses. Increases or decreases in the costs of fuel and natural gas supply are reflected in retail rates through the FAC and GSC, subject to the approval of the Kentucky Commission.

Fuel for electric generation decreased $8 million in the three months ended March 31, 2010, primarily due to:

- Decreased commodity and transportation costs for coal ($4 million)
- Decreased volumes of fuel usage ($4 million) due to decreased wholesale sales

Power purchased expense decreased $2 million in the three months ended March 31, 2010, primarily due to decreased purchased volumes from KU under the mutual agreement due to increased demand by KU native load customers and reduced availability of LG&E's lower cost generation to supply KU's demand, as a result of LG&E's unit outages.

Gas supply expenses decreased $69 million in the three months ended March 31, 2010, primarily due to:

- Decreased cost of net gas supply billed to customers ($97 million) resulting from lower cost per Mcf

Partially offset by:

- Higher volumes of natural gas delivered to retail customers ($27 million) due to increased demand

Other operation and maintenance expense decreased $36 million in the three months ended March 31, 2010, due to decreased maintenance expense ($32 million) and decreased other operation expense ($4 million).

Maintenance expense decreased $32 million in the three months ended March 31, 2010, primarily due to:

- Decreased distribution expense ($36 million) due to tree trimming and maintenance of overhead lines and line transformers as a result of 2009 winter storm restoration

Partially offset by:

- Increased boiler and electric maintenance expense ($4 million) due to increased scheduled unit outages

Other operation expense decreased $4 million in the three months ended March 31, 2010, primarily due to:

- Decreased distribution expense ($4 million) due to repair of overhead lines and administrative support costs, including increased call center support and public safety response team support, as a result of 2009 winter storm restoration
- Decreased pension expense ($1 million)
- Decreased workers' compensation expense ($1 million)

Partially offset by:

- Increased administrative and general expense ($3 million) due to increased DSM program spending

Derivative loss (gain) increased $6 million in the three months ended March 31, 2010, primarily due to a loss in 2010, versus a gain in 2009, from the change in the value of ineffective interest rate swaps.

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

	Three Months Ended March 31, 2010	Three Months Ended March 31, 2009
Statutory federal income tax rate	35.0 %	35.0 %
State income taxes, net of federal benefit	3.6	(6.4)
Qualified production activities deduction	(0.7)	(10.2)
Amortization of investment tax credits	(1.2)	(17.2)
Other differences	(1.4)	(1.2)
Effective income tax rate	35.3 %	0.0 %

The effective income tax rate increased to more historically normal levels for the three months ended March 31, 2010, compared to the three months ended March 31, 2009, primarily due to increased pretax income. State income taxes, net of federal benefit was also lower in the three months ended March 31, 2009, due to a coal credit recorded in 2009. The decreases in the qualified production activities deduction and the amortization of investment tax credits are directly attributable to the quarter over quarter increase in pretax income.

Liquidity and Capital Resources

LG&E uses net cash generated from its operations, external financing (including financing from affiliates) and/or infusions of capital from its parent to fund construction of plant and equipment and the payment of dividends. As of March 31, 2010, LG&E had a working capital deficiency of $151 million, primarily due to short-term debt from affiliates associated with the repurchase of certain of its tax-exempt bonds totaling $163 million, and $120 million of tax-exempt bonds which allow the investors to put the bonds back to the Company causing them to be classified as current portion of long-term debt. The Company has adequate liquidity facilities to repurchase any bonds put back to the Company. The repurchased bonds are being held until they can be refinanced or restructured. Working capital deficiencies can be funded through an intercompany money pool agreement or through bilateral lines of credit. See Note 6 of Notes to Financial Statements. LG&E believes that its sources of funds will be sufficient to meet the needs of its business in the foreseeable future.

Operating Activities

Cash provided by operations for the three months ended March 31, 2010 was $92 million less than cash provided by operations for the three months ended March 31, 2009, and was primarily the result of decreases in cash due to changes in:

- Materials and supplies ($52 million) primarily due to gas price decreases
- Gas supply clause receivable, net ($50 million) due to the timing of GSC collections
- Accounts receivable ($36 million) primarily due to timing on collection of accounts and colder weather in the first quarter of 2010
- Pension and postretirement funding ($19 million) primarily due to timing of pension contributions
- Collateral deposit – interest rate swap ($3 million) due to decreased collateral required related to decrease in derivative liability in 2010 compared to 2009

These decreases were partially offset by increases in cash due to changes in:

- Earnings, net of non-cash items ($38 million)
- Accounts payable ($25 million) primarily due to higher gas costs in 2009 and timing of payments
- Other current assets and liabilities ($3 million)
- Other ($2 million)

Investing Activities

Net cash flows provided by investing activities were $17 million and net cash flows used for investing activities were $42 million in the three months ended March 31, 2010 and 2009, respectively, resulting in an increase in net cash provided by investing activities of $59 million. The increase in investing cash inflows is due to the sale of assets to an affiliate of $48 million, decreased capital expenditures of $12 million and decreased changes in non-hedging derivatives of $1 million.

Financing Activities

Net cash flows used for financing activities were $77 million and $109 million in the three months ended March 31, 2010 and 2009, respectively, resulting in a decrease in net cash used for financing activities of $32 million. The decrease in financing cash outflows is due to lower short-term borrowings net of repayments from an affiliated company of $27 million and decreased dividend payments of $5 million.

See Note 6 of Notes to Financial Statements for information of redemptions, maturities and issuances of long-term debt.

Future Capital Requirements

LG&E'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. LG&E expects its capital expenditures for the three year period ending December 31, 2012, to total approximately $800 million, consisting primarily of on-going construction related to distribution assets totaling approximately $415 million, on-going construction related to generation assets totaling approximately $260 million, redevelopment of the Ohio Falls hydroelectric facility totaling approximately $55 million, information technology projects of approximately $35 million, other projects of $30 million, and construction of TC2 totaling approximately $5 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. Credit market conditions can affect aspects of the availability, terms or methods in which the Company funds its capital requirements. LG&E anticipates funding future capital requirements through operating cash flow, debt and/or infusions of capital from its parent.

LG&E has a variety of funding alternatives available to meet its capital requirements. The Company participates in an intercompany money pool agreement wherein E.ON U.S. and/or KU make funds of up to $400 million available to the Company at market-based rates. See Note 6 of Notes to Financial Statements. Fidelia also provides long-term intercompany funding to LG&E.

Regulatory approvals are required for LG&E to incur additional debt. The FERC authorizes the issuance of short-term debt while the Kentucky Commission authorizes the issuance of long-term debt. In November 2009, LG&E received a two-year authorization from the FERC to borrow up to $400 million in short-term funds. As of March 31, 2010, LG&E has borrowed $124 million of this authorized amount. See Note 6 of Notes to Financial Statements.

A significant portion of LG&E's short-term debt balance ($163 million) is for borrowings incurred to repurchase auction rate tax-exempt bonds. Following the repurchase, the auction rate tax-exempt bonds have been removed from the balance sheet. However, these bonds are being held until they can be refinanced or restructured. Given the uncertainty surrounding the timing of when the bonds could be remarketed to the public due to the current state of the capital markets and the $400 million limit on short-term debt, in November 2009, the Company sought and received authority from the Kentucky Commission to issue up to $50 million of new long-term debt to its affiliate, Fidelia. The Company currently believes this authorization provides the necessary flexibility to address any liquidity needs.

The Company's debt ratings as of March 31, 2010, were:

	Moody's	S&P
Unenhanced 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. In connection with E.ON U.S.'s announcement that E.ON AG and E.ON US Investments Corp. had entered into a definitive agreement with PPL to sell to PPL all the equity interests of E.ON U.S., Moody's placed the debt ratings of the Company under review for possible downgrade. S&P affirmed the existing ratings of the Company. 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

Management 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.

LG&E 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, management has assessed the effectiveness of the Company's internal control over financial reporting as of December 31, 2009, using the criteria set forth by the Committee of Sponsoring Organizations of the Treadway Commission in *Internal Control – Integrated Framework.* Management has concluded that, as of December 31, 2009, the Company's internal control over financial reporting was effective based on those criteria. There have been no changes in the Company's internal control over financial reporting that occurred during the three months ended March 31, 2010, that has materially affected, or is reasonably likely to materially affect the Company's internal control over financial reporting.

The effectiveness of the Company's internal control over financial reporting as of December 31, 2009, was audited by PricewaterhouseCoopers LLP, an independent accounting firm, as stated in its report which is included in the 2009 LG&E Annual Report.

Legal Proceedings

For a description of the significant legal proceedings, including, but not limited to, certain rates and regulatory, environmental, climate change and litigation matters, involving LG&E, reference is made to the information under the following captions of the Company's Annual Report for the year ended December 31, 2009: 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, 7, and 10 of this quarterly report. Except as described in this quarterly report, to date, the proceedings reported in the Company's Annual Report for the year ended December 31, 2009 have not materially changed.

Other

In the normal course of business, other lawsuits, claims, environmental actions and other governmental proceedings arise against LG&E. To the extent that damages are assessed in any of these lawsuits, the Company 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 the Company's financial position or results of operations.

LOUISVILLE GAS & ELECTIRC COMPANY
FINANCIAL STATEMENTS

JUNE 30, 2010

Louisville Gas and Electric Company

Condensed Financial Statements and Additional Information

(Unaudited)

As of June 30, 2010 and December 31, 2009
and for the three-month and six-month periods ended
June 30, 2010 and 2009

INDEX OF ABBREVIATIONS

AG	Attorney General of Kentucky
ARO	Asset Retirement Obligation
ASC	Accounting Standards Codification
BART	Best Available Retrofit Technology
CAIR	Clean Air Interstate Rule
CAMR	Clean Air Mercury Rule
CATR	Clean Air Transport Rule
CCN	Certificate of Public Convenience and Necessity
Clean Air Act	The Clean Air Act, as amended in 1990
CMRG	Carbon Management Research Group
Companies	LG&E and KU
Company	LG&E
DSM	Demand Side Management
ECR	Environmental Cost Recovery
E.ON	E.ON AG
E.ON U.S.	E.ON U.S. LLC
E.ON U.S. Services	E.ON U.S. 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)
GHG	Greenhouse Gas
GSC	Gas Supply Clause
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
LG&E	Louisville Gas and Electric Company
Mcf	Thousand Cubic Feet
MISO	Midwest Independent Transmission System Operator, Inc.
MMBtu	Million British thermal units
Moody's	Moody's Investors Service, Inc.
Mw	Megawatts
Mwh	Megawatt hours
NAAQS	National Ambient Air Quality Standards
NOx	Nitrogen Oxide
OCI	Other Comprehensive Income
PBR	Performance Based Rates
PPL	PPL Corporation
S&P	Standard & Poor's Ratings Services
SCR	Selective Catalytic Reduction
SERC	SERC Reliability Corporation
SIP	State Implementation Plan
SO_2	Sulfur Dioxide
TC1	Trimble County Unit 1
TC2	Trimble County Unit 2
Virginia Commission	Virginia State Corporation Commission
WNA	Weather Normalization Adjustment

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PRICEWATERHOUSECOOPERS

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Louisville KY 40202-4264
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Report of Independent Accountants

To Shareholder of Louisville Gas and Electric Company:

We have reviewed the accompanying condensed balance sheet of Louisville Gas and Electric Company as of June 30, 2010, and the related condensed statements of income, comprehensive income, and retained earnings for the three-month and six-month periods ended June 30, 2010 and 2009 and the condensed statement of cash flows for the six-month periods ended June 30, 2010 and 2009. This condensed interim financial information is the responsibility of the Company's management.

We conducted our review in accordance with standards established by the American Institute of Certified Public Accountants. A review of interim financial information consists principally of applying analytical procedures and making inquiries of persons responsible for financial and accounting matters. It is substantially less in scope than an audit conducted in accordance with auditing standards generally accepted in the United States of America, the objective of which is the expression of an opinion regarding the financial information taken as a whole. Accordingly, we do not express such an opinion.

Based on our review, we are not aware of any material modifications that should be made to the accompanying condensed interim financial information for it to be in conformity with accounting principles generally accepted in the United States of America.

We have previously audited, in accordance with auditing standards generally accepted in the United States of America, the balance sheet of Louisville Gas and Electric Company as of December 31, 2009, and the related statements of income, comprehensive income, retained earnings, and cash flows for the year then ended (not presented herein), and in our report dated March 19, 2010, we expressed an unqualified opinion on those financial statements. In our opinion, the information set forth in the accompanying condensed balance sheet information as of December 31, 2009, is fairly stated in all material respects in relation to the balance sheet from which it has been derived.

PricewaterhouseCoopers LLP

August 11, 2010

Louisville Gas and Electric Company
Condensed Statements of Income
(Unaudited)
(Millions of $)

	Three Months Ended June 30, 2010	Three Months Ended June 30, 2009	Six Months Ended June 30, 2010	Six Months Ended June 30, 2009
Operating revenues				
Electric (Note 9)	$ 247	$ 228	$ 479	$ 463
Gas	32	49	166	242
Total operating revenues	279	277	645	705
Operating expenses				
Fuel for electric generation	90	83	173	174
Power purchased (Note 9)	12	14	29	33
Gas supply expenses	12	29	93	179
Other operation and maintenance expenses	87	84	174	207
Depreciation and amortization	35	34	69	67
Total operating expenses	236	244	538	660
Operating income	43	33	107	45
Derivative loss (gain) (Note 3)	10	(11)	11	(16)
Other expense – net (Note 3)	-	-	1	1
Interest expense (Notes 3 and 6)	5	4	9	8
Interest expense to affiliated companies (Notes 6 and 9)	7	7	14	14
Income before income taxes	21	33	72	38
Income tax expense (Note 5)	7	12	25	12
Net income	$ 14	$ 21	$ 47	$ 26

The accompanying notes are an integral part of these condensed financial statements.

Condensed Statements of Retained Earnings
(Unaudited)
(Millions of $)

	Three Months Ended June 30, 2010	Three Months Ended June 30, 2009	Six Months Ended June 30, 2010	Six Months Ended June 30, 2009
Balance at beginning of period	$ 758	$ 710	$ 755	$ 740
Net income	14	21	47	26
	772	731	802	766
Cash dividends declared on common stock (Note 9)	-	(45)	(30)	(80)
Balance at end of period	$ 772	$ 686	$ 772	$ 686

The accompanying notes are an integral part of these condensed financial statements.

Louisville Gas and Electric Company
Condensed Balance Sheets
(Unaudited)
(Millions of $)

Assets	June 30, 2010	December 31, 2009
Current assets:		
Cash and cash equivalents	$ 6	$ 5
Accounts receivable, net:		
Customer – less reserves of $1 million as of June 30, 2010 and December 31, 2009, respectively	135	131
Other – less reserves of $1 million as of June 30, 2010 and December 31, 2009, respectively	8	12
Accounts receivable from affiliated companies	18	53
Materials and supplies:		
Fuel (predominantly coal)	69	61
Gas stored underground	19	56
Other materials and supplies	33	33
Income tax receivable	12	-
Derivative asset (Note 3)	2	2
Deferred income taxes – net (Note 5)	4	4
Regulatory assets (Note 2)	11	14
Prepayments and other current assets	8	12
Total current assets	325	383
Utility plant:		
At original cost	4,264	4,200
Less: reserve for depreciation	1,748	1,708
Total utility plant, net	2,516	2,492
Construction work in progress	323	342
Net utility plant and construction work in progress	2,839	2,834
Deferred debits and other assets:		
Collateral deposit (Note 3)	17	17
Regulatory assets (Note 2):		
Pension and postretirement benefits	204	204
Other	126	125
Other assets	5	5
Total deferred debits and other assets	352	351
Total assets	$ 3,516	$ 3,568

The accompanying notes are an integral part of these condensed financial statements.

Louisville Gas and Electric Company
Condensed Balance Sheets (cont.)
(Unaudited)
(Millions of $)

Liabilities and Equity	June 30, 2010	December 31, 2009
Current liabilities:		
Current portion of long-term bonds (Notes 3 and 6)	$ 120	$ 120
Notes payable to affiliated company (Notes 6 and 9)	137	170
Accounts payable	79	97
Accounts payable to affiliated companies (Note 9)	28	28
Accrued income taxes	-	15
Customer deposits	24	22
Derivative liability (Note 3)	1	2
Regulatory liabilities (Note 2)	12	38
Other current liabilities	38	41
Total current liabilities	439	533
Long-term debt:		
Long-term bonds (Note 3 and 6)	291	291
Long-term debt to affiliated company (Notes 3, 6 and 9)	485	485
Total long-term debt	776	776
Deferred credits and other liabilities:		
Accumulated deferred income taxes (Note 5)	395	373
Accumulated provision for pensions and related benefits (Note 4)	188	198
Investment tax credit (Note 5)	47	48
Asset retirement obligations	32	31
Regulatory liabilities (Note 2):		
Accumulated cost of removal of utility plant	265	256
Deferred income taxes – net	37	41
MISO exit	3	3
Other	3	3
Customer advances for construction	7	8
Derivative liability (Note 3)	42	28
Other liabilities	15	17
Total deferred credits and other liabilities	1,034	1,006
Common equity:		
Common stock, without par value - Authorized 75,000,000 shares, outstanding 21,294,223 shares	424	424
Additional paid-in capital	84	84
Accumulated other comprehensive loss	(13)	(10)
Retained earnings (Note 9)	772	755
Total common equity	1,267	1,253
Total liabilities and equity	$ 3,516	$ 3,568

The accompanying notes are an integral part of these condensed financial statements.

Louisville Gas and Electric Company
Condensed Statements of Cash Flows
(Unaudited)
(Millions of $)

	For the Six Months Ended June 30, 2010	2009
Cash flows from operating activities:		
Net income	$ 47	$ 26
Items not requiring cash currently:		
Depreciation and amortization	69	67
Deferred income taxes – net	18	6
Provision for pension and postretirement plans	11	14
Derivative liability	15	(23)
Other	(2)	(5)
Changes in current assets and liabilities:		
Accounts receivable	(13)	71
Materials and supplies	29	78
Income tax receivable	(12)	-
Gas supply clause receivable – net	(28)	30
Fuel adjustment clause	(3)	5
Environmental cost recovery	5	(2)
Accounts payable	(8)	(31)
Accrued income taxes	(15)	(6)
Other current assets and liabilities	2	4
Change in collateral deposit – interest rate swap (Note 3)	-	7
Pension and postretirement funding (Note 4)	(23)	(11)
Other	(8)	9
Net cash provided by operating activities	84	239
Cash flows from investing activities:		
Construction expenditures	(68)	(92)
Assets sold to affiliate	48	-
Change in non-hedging derivatives	-	2
Net cash used for investing activities	(20)	(90)
Cash flows from financing activities:		
Short-term borrowings from affiliated company – net (Note 6)	(33)	(69)
Payment of dividends (Note 9)	(30)	(80)
Net cash used for financing activities	(63)	(149)
Change in cash and cash equivalents	1	-
Cash and cash equivalents at beginning of period	5	4
Cash and cash equivalents at end of period	$ 6	$ 4

The accompanying notes are an integral part of these condensed financial statements.

Louisville Gas and Electric Company
Condensed Statements of Comprehensive Income
(Unaudited)
(Millions of $)

	Three Months Ended June 30, 2010	Three Months Ended June 30, 2009	Six Months Ended June 30, 2010	Six Months Ended June 30, 2009
Net income	$ 14	$ 21	$ 47	$ 26
(Loss) gain on derivative instruments and hedging activities - net of tax benefit (expense) of $1 million, $(2) million, $1 million, and $(2) million, respectively (Note 3)	(2)	2	(3)	4
Comprehensive income	$ 12	$ 23	$ 44	$ 30

The accompanying notes are an integral part of these condensed financial statements.

Louisville Gas and Electric Company
Notes to Condensed Financial Statements
(Unaudited)

Note 1 - General

LG&E'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 condensed financial statements include all adjustments, consisting only of normal recurring adjustments, necessary for fair statements of income and retained earnings, balance sheets, and statements of cash flows and comprehensive income 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 condensed financial statements and notes should be read in conjunction with the Company's Financial Statements and Additional Information ("Annual Report") for the year ended December 31, 2009, including the audited financial statements and notes therein. The December 31, 2009 Condensed Balance Sheet included herein is derived from the December 31, 2009 audited balance sheet. Amounts reported in the Condensed Statements of Income are not necessarily indicative of amounts expected for the respective annual periods due to the effects of seasonal temperature variations on energy consumption, regulatory rulings, the timing of maintenance on electric generating units, changes in mark-to-market valuations, changing commodity prices and other factors.

Certain reclassification entries have been made to the previous years' financial statements to conform to the 2010 presentation with no impact on capitalization or previously reported net income. However, total assets and liabilities both increased by $1 million, cash flows provided by operating activities decreased by $4 million and cash flows used for investing activities decreased by $4 million.

PPL Acquisition

On April 28, 2010, E.ON U.S. announced that a Purchase and Sale Agreement (the "Agreement") had been entered into among E.ON US Investments, PPL and E.ON.

The Agreement provides for the sale of E.ON U.S. to PPL. Pursuant to the Agreement, at closing, PPL will acquire all of the outstanding limited liability company interests of E.ON U.S. for cash consideration of $2.1 billion. In addition, pursuant to the Agreement, PPL agreed to assume $925 million of pollution control bonds and to repay indebtedness owed by E.ON U.S. and its subsidiaries to E.ON US Investments and its affiliates. Such affiliate indebtedness is currently estimated to be $4.6 billion. The aggregate consideration payable by PPL on closing, $7.6 billion (including the assumed indebtedness), is subject to adjustment for specified incremental investment in E.ON U.S. that will potentially be made by E.ON US Investments and its affiliates prior to closing.

The transaction is subject to customary closing conditions, including the expiration or termination of the applicable waiting period under the Hart-Scott-Rodino Act, receipt of required regulatory approvals (including state regulators in Kentucky, Virginia and Tennessee, and the FERC) and the absence of injunctions or restraints imposed by governmental entities. Subject to receipt of required approvals, the transaction is expected to close by the end of 2010. Change of control and financing-related applications were filed on May 28, 2010, with the Kentucky

Commission and on June 15, 2010, with the Virginia Commission and the Tennessee Regulatory Authority. An application with the FERC was filed on June 28, 2010. During the second quarter of 2010, a number of parties were granted intervenor status in the Kentucky Commission proceedings and data request filings and responses occurred. Hearings in the Kentucky Commission proceedings are scheduled for September 8, 2010. Early termination of the final Hart-Scott-Rodino waiting period was received on August 2, 2010.

Based upon credit and financial market conditions, the anticipated PPL acquisition and other factors, the Company anticipates completing certain re-financing transactions and, where applicable, has applied for regulatory approvals for such transactions. LG&E anticipates issuing up to $535 million in public first mortgage bonds, the proceeds of which will substantially be used to refund existing long-term intercompany debt. As required by existing covenants, in connection with the issuance of any such secured debt, LG&E would also collateralize certain outstanding pollution control bond debt series which are presently unsecured. Upon such collateralization, approximately $574 million in existing pollution control debt would become secured debt, supported by a first mortgage lien. Subject to regulatory approvals and other conditions, LG&E may complete these transactions, in whole or in part, during late 2010 and early 2011.

See Note 6 of Notes to Condensed Financial Statements for further information regarding the refinancing, remarketing or conversion of existing pollution control debt.

Recent Accounting Pronouncements

Fair Value Measurements

In January 2010, the FASB issued guidance related to fair value measurement disclosures requiring separate disclosure of amounts of significant transfers in and out of level 1 and level 2 fair value measurements and separate information about purchases, sales, issuances and settlements within level 3 measurements. This guidance is effective for the interim and annual reporting periods beginning after December 15, 2009, except for the disclosures about the roll-forward of activity in level 3 fair value measurements. Those disclosures are effective for fiscal years beginning after December 15, 2010, and for interim periods within those fiscal years. This guidance has no impact on the Company's results of operations, financial position, liquidity or disclosures.

Note 2 - Rates and Regulatory Matters

For a description of each line item of regulatory assets and liabilities and for descriptions of certain matters which may not have undergone material changes relating to the period covered by this quarterly report, reference is made to Note 2 of LG&E's Annual Report for the year ended December 31, 2009.

2010 Electric and Gas Rate Cases

In January 2010, LG&E filed an application with the Kentucky Commission requesting an increase in electric base rates of approximately 12%, or $95 million annually, and its gas base rates of approximately 8%, or $23 million annually, including an 11.5% return on equity for electric and gas. LG&E requested the increase, based on the twelve month test year ended

October 31, 2009, to become effective on and after March 1, 2010. The requested rates were suspended until August 1, 2010. A number of intervenors entered the rate case, including the Kentucky Attorney General's office, certain representatives of industrial and low-income groups and other third parties, and submitted filings challenging the Company's requested rate increases, in whole or in part. A hearing was held on June 8, 2010. LG&E and all of the intervenors except for the AG agreed to a stipulation providing for an increase in electric base rates of $74 million annually and gas base rates of $17 million annually and filed a request with the Kentucky Commission to approve such settlement. An Order in the proceeding was issued in July 2010, approving all the provisions in the stipulation, with rates effective on and after August 1, 2010.

Regulatory Assets and Liabilities

The following regulatory assets and liabilities were included in LG&E's Balance Sheets:

(in millions)	June 30, 2010	December 31, 2009
Current regulatory assets:		
GSC	$ 3	$ 3
ECR	2	7
FAC	3	-
MISO exit	1	1
Other	2	3
Total current regulatory assets	$ 11	$ 14
Non-current regulatory assets:		
Storm restoration	$ 67	$ 67
ARO	31	30
Unamortized loss on bonds	21	22
MISO exit	4	4
Other	3	2
Subtotal non-current regulatory assets	126	125
Pension benefits	204	204
Total non-current regulatory assets	$ 330	$ 329
Current regulatory liabilities:		
GSC	$ 6	$ 34
DSM	6	4
Total current regulatory liabilities	$ 12	$ 38
Non-current regulatory liabilities:		
Accumulated cost of removal of utility plant	$ 265	$ 256
Deferred income taxes – net	37	41
MISO exit	3	3
Other	3	3
Total non-current regulatory liabilities	$ 308	$ 303

LG&E does not currently earn a rate of return on the GSC, ECR, FAC, and gas performance-based ratemaking (included in "GSC" above) regulatory assets which are separate recovery mechanisms with recovery within twelve months. No return is earned on the pension benefits regulatory asset that represents the changes in funded status of the plans. LG&E will recover this asset through pension expense included in the calculation of base rates. No return is currently earned on the ARO asset. When an asset with an ARO is retired, the related ARO regulatory asset will be offset against the associated ARO regulatory liability, ARO asset and ARO liability. ARO liabilities are included in other non-current regulatory liabilities. A return is earned on the unamortized loss on bonds, including the portion in other current regulatory assets, and these costs are recovered through amortization over the life of the debt. LG&E earned a rate of return on the balance of Mill Creek Ash Pond costs included in other regulatory assets at December 31, 2009, as well as recovery of these costs. There is no remaining balance as of June 30, 2010. The Company received approval in its current base rate cases to recover the storm restoration regulatory asset over a ten year period. The Company also received approval for adjustments to the amortization of CMRG and KCCS contributions, included in other non-current regulatory assets. The Company recovers through the calculation of base rates, the amortization of the net MISO exit regulatory asset incurred through April 30, 2008, and other current and non-current regulatory assets including the East Kentucky Power Cooperative FERC transmission settlement agreement and rate case expenses. The regulatory liabilities for the MISO exit include administrative charges collected via base rates from May 2008 through February 5, 2009, and refunds of the exit fee. The MISO regulatory liability will be netted against the remaining costs of withdrawing from the MISO, except for a small portion of the refund which occurred in 2010 which will be addressed in a later rate case, per a Kentucky Commission Order, in the current Kentucky base rate case. Refunds from the MISO for a portion of the cost of exiting will also be netted against the remaining balances of these costs in the current Kentucky base rate cases as well as in future Kentucky base rate cases. Other non-current regulatory liabilities include a portion of GSC.

GSC. In December 2009, LG&E filed with the Kentucky Commission an application to extend and modify its existing gas cost PBR. The current PBR was set to expire at the end of October 2010. In April 2010, the Kentucky Commission issued an Order approving a five year extension and the requested minor modifications to the PBR effective November 2010.

ECR. In July 2010, the Kentucky Commission initiated a six-month review of LG&E's environmental surcharge for the billing period ending April 2010. An order is expected in the fourth quarter of 2010.

In January 2010, the Kentucky Commission initiated a six-month review of LG&E's environmental surcharge for the billing period ending October 2009. In May 2010, an Order was issued approving the amounts billed through the ECR during the six-month period and the rate of return on capital and allowing recovery of the under-recovery position in subsequent monthly filings.

In June 2009, the Company filed an application for a new ECR plan with the Kentucky Commission seeking approval to recover investments in environmental upgrades and operations and maintenance costs at the Company's generating facilities. During 2009, LG&E reached a unanimous settlement with all parties to the case, and the Kentucky Commission issued an Order approving LG&E's application. Recovery on customer bills through the monthly ECR surcharge for these projects began with the February 2010 billing cycle.

FAC. In January 2010, the Kentucky Commission initiated a six-month review of LG&E's FAC mechanism for the expense period ended August 2009. In May 2010, an Order was issued approving the charges and credits billed through the FAC during the review period.

Storm Restoration. In January 2009, a significant ice storm passed through LG&E's service territory causing approximately 205,000 customer outages and was followed closely by a severe wind storm in February 2009 that caused approximately 37,000 customer outages. LG&E incurred $44 million in incremental operation and maintenance expenses and $10 million in capital expenditures related to the restoration following the two storms. The Company filed an application with the Kentucky Commission in April 2009, requesting approval to establish a regulatory asset and defer for future recovery approximately $45 million in incremental operation and maintenance expenses related to the storm restoration. In September 2009, the Kentucky Commission issued an Order allowing the Company to establish a regulatory asset of up to $45 million based on its actual costs for storm damages and service restoration due to the January and February 2009, storms. In September 2009, the Company established a regulatory asset of $44 million for actual costs incurred. The Company received approval in its current base rate cases to recover this asset over a ten year period beginning August 1, 2010.

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, LG&E filed an application with the Kentucky Commission requesting approval to establish a regulatory asset and defer for future recovery approximately $24 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 $24 million based on its actual costs for storm damages and service restoration due to Hurricane Ike. In December 2008, the Company established a regulatory asset of $24 million for actual costs incurred. The Company received approval in its current electric base rate case to recover this asset over a ten year period beginning August 1, 2010.

Other Regulatory Matters

Wind Power Agreements. In September 2009, the Companies filed an application and supporting testimony with the Kentucky Commission for approval of wind power purchase contracts and cost recovery mechanisms, under which LG&E and KU would jointly purchase respective assigned portions of the output of two Illinois wind farms totaling an aggregate 109.5 Mw. In October 2009, the Kentucky Commission issued an Order denying the Companies' request to establish a surcharge for recovery of the costs of purchasing wind power. In March 2010, LG&E and KU delivered notices of termination under provisions of the wind power contracts. The Companies also filed a motion with the Kentucky Commission noting the termination of the contracts and seeking withdrawal of their application in the related regulatory proceeding. In April 2010, the Kentucky Commission issued an Order allowing the Companies to withdraw their pending application.

TC2 Depreciation. In August 2009, LG&E and KU jointly filed an application with the Kentucky Commission to approve new common depreciation rates for applicable jointly-owned TC2-related generating, pollution control and other plant equipment and assets. During December 2009, the Kentucky Commission extended the data discovery process through January 2010, and authorized LG&E and KU on an interim basis to begin using the depreciation rates for

TC2 as proposed in the application. In March 2010, the Kentucky Commission issued a final Order approving the use of the proposed depreciation rates on a permanent basis.

TC2 Transmission Matters. LG&E's and KU's CCN for a transmission line associated with the TC2 construction has been challenged by certain property owners in Hardin County, Kentucky. In August 2006, LG&E and KU obtained a successful dismissal of the challenge at the Franklin County Circuit Court, which was reversed by the Kentucky Court of Appeals in December 2007. In April 2009, the Kentucky Supreme Court granted LG&E's and KU's motion for discretionary review of the Court of Appeal's decision. LG&E's and KU's proceeding before the Kentucky Supreme Court, which seeks reinstatement of the Circuit Court dismissal of the CCN challenge, has been fully briefed and oral argument occurred during March 2010. A ruling on the matter could occur during the second half of 2010.

During 2008, LG&E's affiliate, KU obtained various successful rulings at the Hardin County Circuit Court confirming its condemnation rights. In August 2008, several landowners appealed such rulings to the Kentucky Court of Appeals. In May 2010, the Kentucky Court of Appeals issued an Order affirming the Hardin Circuit Court's finding that KU had the right to condemn easements on the properties. In May 2010, the landowners filed a petition for reconsideration with the Court of Appeals. In July 2010, the Court of Appeals denied that petition. The landowners may seek discretionary review of that denial by the Kentucky Supreme Court on or before August 21, 2010.

As a result of the aforementioned proceedings delaying access to certain properties in Hardin County, KU obtained easements to allow construction of temporary transmission facilities for approximately ten years, which bypass the disputed properties while the litigated issues are resolved. In December 2009, the Kentucky Commission granted CCNs for the relevant temporary segments. In January 2010, the Franklin County Circuit Court issued Orders denying the property owners' request for a stay of construction and upholding the Kentucky Commission's denial of their intervenor status.

In a separate proceeding, certain Hardin County landowners have filed an action in federal district court in Louisville, Kentucky against the U.S. Army challenging the same transmission line claiming that certain Fort Knox-related sections of the line failed to comply with certain National Historic Preservation Act procedural requirements. In October 2009, the federal court granted the defendants' motion for summary judgment and dismissed the plaintiffs' claims. During November 2009, the petitioners filed submissions for review of the decision with the 6th Circuit Court of Appeals. That appeal has since been voluntarily withdrawn by the plaintiffs.

Consistent with the regulatory authorizations and relevant legal proceedings, the Company has completed construction activities on temporary or permanent transmission line segments, respectively. During the second quarter of 2010, LG&E and KU placed into operation an appropriate combination of permanent and temporary sections of the transmission line. While LG&E and KU are not currently able to predict the ultimate outcome and possible financial effects of the remaining legal proceedings, LG&E and KU do not believe the matter involves relevant or continuing risks to operations.

LG&E and KU are not currently able to predict the ultimate outcome and possible effects, if any, on the construction schedule relating to the permanent transmission line approval, land acquisition and permitting proceedings.

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 Regional Reliability Organizations ("RROs") by the North American Electric Reliability Corporation ("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. LG&E and KU are members of the SERC, which acts as LG&E's and KU's RRO. During December 2009, the SERC and LG&E and KU agreed to settlements involving penalties totaling less than $1 million for each utility related to their self-reports during June and October 2008, concerning possible violations of standards. During December 2009 and April and July 2010, LG&E and KU submitted four self-reports relating to various standards, which self-reports remain in the early stages of RRO review, and therefore, the Companies are unable to estimate the outcome of these matters. Mandatory reliability standard settlements commonly also include non-penalty elements, including compliance steps and mitigation plans. Settlements with the SERC proceed to NERC and FERC review before becoming final. While LG&E and KU believe they are in compliance with the mandatory reliability standards, other events of potential non-compliance may be identified from time-to-time. The Companies cannot predict such potential violations or the outcomes of the existing self-reports described above.

Gas Customer Choice Study. In April 2010, the Kentucky Commission commenced a proceeding to investigate natural gas retail competition programs, their regulatory, financial and operational aspects and potential benefits, if any, of such programs to Kentucky consumers. A number of entities, including LG&E, are parties to the proceeding. An order in the proceeding may be issued in late 2010.

Note 3 - Financial Instruments

The cost and estimated fair values of LG&E's non-trading financial instruments as of June 30, 2010 and December 31, 2009 follow:

(in millions)	June 30, 2010 Carrying Value	June 30, 2010 Fair Value	December 31, 2009 Carrying Value	December 31, 2009 Fair Value
Long-term bonds (including current portion of $120 million)	$ 411	$ 414	$ 411	$ 411
Long-term debt to affiliated company	485	536	485	512
Derivative liability – interest rate swaps	42	42	28	28

The long-term debt valuations reflect prices quoted by dealers. The fair value of the long-term debt to affiliated company 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 LG&E's credit ratings and default risk. The fair values of the swaps reflect price quotes from dealers, consistent with the fair value measurements and disclosures topic of the FASB ASC. The fair values of cash and cash equivalents, accounts receivable, accounts payable and notes payable are substantially the same as their carrying values.

LG&E is subject to interest rate and commodity price risk related to on-going business operations. It currently manages these risks using derivative financial instruments, including swaps and forward contracts. The Company's policies allow for the interest rate risk to be managed through the use of fixed rate debt, floating rate debt and interest rate swaps. At June 30, 2010, a 100 basis point change in the benchmark rate on LG&E's variable rate debt, not effectively hedged by an interest rate swap, would impact pre-tax interest expense by $2 million annually.

LG&E has classified the applicable financial assets and liabilities that are accounted for at fair value into the three levels of the fair value hierarchy, as defined by the fair value measurements and disclosures topic of the FASB ASC, as follows:

- Level 1 - Observable inputs that reflect quoted prices (unadjusted) for identical assets or liabilities in active markets.
- Level 2 - Include other inputs that are directly or indirectly observable in the marketplace.
- Level 3 - Unobservable inputs which are supported by little or no market activity.

Interest Rate Swaps. LG&E uses 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 is intended to mitigate risk, earnings and cash flow volatility and is not speculative in nature.

The fair value of the interest rate swaps is determined by a quote from the counterparty. This value is verified monthly by the Company using a model that calculates the present value of future payments under the swap utilizing current swap market rates obtained from another dealer active in the swap market and validated by market transactions. Market liquidity is considered; however, the valuation does not require an adjustment for market liquidity as the market is very active for the type of swaps used by the Company. LG&E considered the impact of counterparty credit risk by evaluating credit ratings and financial information. All counterparties had strong investment grade ratings at June 30, 2010. LG&E did not have any credit exposure to the swap counterparties, as it was in a liability position at June 30, 2010; therefore, the market valuation required no adjustment for counterparty credit risk. In addition, the Company and the counterparties have agreed to post margin if the credit exposure exceeds certain thresholds. Using these valuation methodologies, the swap contracts are considered level 2 based on measurement criteria in the fair value measurements and disclosures topic of the FASB ASC. Cash collateral for interest rate swaps is classified as a long-term asset and is a level 1 measurement based on the funds being held in a demand deposit account.

LG&E was party to various interest rate swap agreements that range in maturity through 2033 with aggregate notional amounts of $179 million as of June 30, 2010 and December 31, 2009. Under these swap agreements, LG&E paid fixed rates averaging 4.52% and received variable rates based on LIBOR or the Securities Industry and Financial Markets Association's municipal swap index averaging 0.27% and 0.20% at June 30, 2010 and December 31, 2009, respectively. One swap hedging a portion of the Company's $83 million Trimble County 2000 Series A bond has been designated as a cash flow hedge and continues to be highly effective. The three remaining interest rate swaps are ineffective.

The interest rate swaps are accounted for on a mark-to-market basis in accordance with the derivatives and hedging topic of the FASB ASC. Financial instruments designated as effective cash flow hedges have resulting gains and losses recorded within other comprehensive income and common equity. The ineffective portion of financial instruments designated as cash flow hedges is recorded to earnings monthly, as is the entire change in the market value of the ineffective swaps. The tables below show the pre-tax amount and income statement location of derivative gains and losses for the change in the mark-to-market value of the ineffective interest rate swaps, as well as the change in the ineffective portion of the interest rate swaps deemed highly effective, for the three and six months ended June 30:

(in millions)	Location of (Gain) Loss Recognized in Income on Derivatives	Amount of (Gain) Loss Recognized in Income on Derivatives Three Months Ended June 30, 2010	Amount of (Gain) Loss Recognized in Income on Derivatives Three Months Ended June 30, 2009
Interest rate swaps – change in the mark-to-market value of ineffective swaps	Derivative loss (gain)	$ 9	$ (11)

For the three month periods ended June 30, 2010 and 2009, LG&E recorded a pre-tax loss of less than $1 million and a pre-tax gain of less than $1 million in interest expense, respectively, to reflect the change in the ineffective portion of the interest rate swaps deemed highly effective.

(in millions)	Location of (Gain) Loss Recognized in Income on Derivatives	Amount of (Gain) Loss Recognized in Income on Derivatives Six Months Ended June 30, 2010	Amount of (Gain) Loss Recognized in Income on Derivatives Six Months Ended June 30, 2009
Interest rate swaps – change in the ineffective portion deemed highly Effective	Interest expense	$ -	$ (1)
Interest rate swaps – change in the mark-to-market value of ineffective swaps	Derivative loss (gain)	10	(17)
Total		$ 10	$ (18)

Amounts recorded in accumulated OCI will be reclassified into earnings in the same period during which the hedged forecasted transaction affects earnings. The amount amortized from other comprehensive income to income in the three month and six month periods ended June 30, 2010 and 2009, was less than $1 million, respectively. The amount expected to be reclassified from OCI to earnings in the next twelve months is less than $1 million.

A decline of 100 basis points in the current market interest rates would reduce the fair value of LG&E's interest rate swaps by approximately $30 million. Such a change could affect OCI if the hedge is effective or the income statement if the hedge is ineffective.

Energy Trading and Risk Management Activities. LG&E 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 the derivatives and hedging topic of the FASB ASC.

Energy trading and risk management contracts are valued using prices based on active trades from Intercontinental Exchange Inc. In the absence of a traded price, midpoints of the best bids and offers are the primary determinants of valuation. When sufficient trading activity is unavailable, other inputs 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 measurement criteria in the fair value measurements and disclosures topic of the FASB ASC. 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 2010 or 2009. Changes in market pricing, interest rate and volatility assumptions were made during both years.

The Company maintains credit policies intended to minimize credit risk in wholesale marketing and trading activities by assessing the creditworthiness of potential counterparties prior to entering into transactions with them and continuing to evaluate their creditworthiness once transactions have been initiated. To further mitigate credit risk, LG&E seeks to enter into netting agreements or require cash deposits, letters of credit and parental company guarantees as security from counterparties. The Company uses S&P, Moody's and definitive qualitative and quantitative data to assess the financial strength of counterparties on an on-going basis. If no external rating exists, LG&E assigns an internally generated rating for which it sets appropriate risk parameters. As risk management contracts are valued based on changes in market prices of the related commodities, credit exposures are revalued and monitored on a daily basis. At June 30, 2010, 100% of the trading and risk management commitments were with counterparties rated BBB-/Baa3 equivalent or better. The Company 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 June 30, 2010 and December 31, 2009, counterparty credit reserves related to energy trading and risk management contracts were less than $1 million.

The net volume of electricity-based financial derivatives outstanding at June 30, 2010 and December 31, 2009, was zero Mwhs and 587,800 Mwhs, respectively. No cash collateral related to the energy trading and risk management contracts was required at June 30, 2010. Cash collateral related to the energy trading and risk management contracts was $2 million at December 31, 2009. Cash collateral related to the energy trading and risk management contracts is categorized as other accounts receivable and is a level 1 measurement based on the criteria previously defined.

The following tables set forth, by level within the fair value hierarchy, LG&E's financial assets and liabilities that were accounted for at fair value on a recurring basis as of June 30, 2010 and December 31, 2009. There were no level 3 measurements for the periods ending June 30, 2010 and December 31, 2009.

Recurring Fair Value Measurements
June 30, 2010

(in millions)	Level 1	Level 2	Total
Financial assets:			
Energy trading and risk management Contracts	$ -	$ 2	$ 2
Interest rate swap cash collateral	17	-	17
Total financial assets	$ 17	$ 2	$ 19
Financial liabilities:			
Energy trading and risk management Contracts	$ -	$ 1	$ 1
Interest rate swaps	-	42	42
Total financial liabilities	$ -	$ 43	$ 43

Recurring Fair Value Measurements
December 31, 2009

(in millions)	Level 1	Level 2	Total
Financial assets:			
Energy trading and risk management contract cash collateral	$ 2	$ -	$ 2
Energy trading and risk management Contracts	-	2	2
Interest rate swap cash collateral	17	-	17
Total financial assets	$ 19	$ 2	$ 21
Financial liabilities:			
Energy trading and risk management Contracts	$ -	$ 2	$ 2
Interest rate swaps	-	28	28
Total financial liabilities	$ -	$ 30	$ 30

The Company does not net collateral against derivative instruments.

Certain of the Company's derivative instruments contain provisions that require the Company to provide immediate and on-going collateralization on derivative instruments in net liability positions based upon the Company's credit ratings from each of the major credit rating agencies. At June 30, 2010, there are no energy trading and risk management contracts with credit risk related contingent features that are in a liability position and no collateral posted in the normal course of business. The aggregate mark-to-market value of all interest rate swaps with credit risk related contingent features that are in a liability position on June 30, 2010, is $29 million, for which the Company has posted collateral of $17 million in the normal course of business. If the credit risk related contingent features underlying these agreements were triggered on June 30, 2010, due to a one notch downgrade in the Company's credit rating, the Company would be required to post an additional $5 million of collateral to its counterparties for the interest rate swaps. At June 30, 2010, a one notch downgrade of the Company's credit rating would have no effect on the energy trading and risk management contracts or collateral required.

The tables below show the fair value and balance sheet location of derivatives designated as hedging instruments as of June 30, 2010 and December 31, 2009:

June 30, 2010 (in millions)	Asset Derivatives Balance Sheet Location	Asset Derivatives Fair Value	Liability Derivatives Balance Sheet Location	Liability Derivatives Fair Value
Interest rate swaps	Other assets	$ -	Long-term derivative liability	$ 23

December 31, 2009 (in millions)	Asset Derivatives Balance Sheet Location	Asset Derivatives Fair Value	Liability Derivatives Balance Sheet Location	Liability Derivatives Fair Value
Interest rate swaps	Other assets	$ -	Long-term derivative liability	$ 19

The tables below show the fair value and balance sheet location of derivatives not designated as hedging instruments as of June 30, 2010 and December 31, 2009:

June 30, 2010 (in millions)	Asset Derivatives Balance Sheet Location	Asset Derivatives Fair Value	Liability Derivatives Balance Sheet Location	Liability Derivatives Fair Value
Interest rate swaps	Other assets	$ -	Long-term derivative liability	$ 19
Energy trading and risk management contracts	Current derivative asset	2	Current derivative liability	1
Total		$ 2		$ 20

December 31, 2009 (in millions)	Asset Derivatives Balance Sheet Location	Asset Derivatives Fair Value	Liability Derivatives Balance Sheet Location	Liability Derivatives Fair Value
Interest rate swaps	Other assets	$ -	Long-term derivative liability	$ 9
Energy trading and risk management contracts	Current derivative asset	2	Current derivative liability	2
Total		$ 2		$ 11

The loss on hedging interest rate swaps recognized in OCI for the three and six month periods ended June 30, 2010, was $3 million and $4 million, respectively. For the three and six month periods ended June 30, 2010, the gain on derivatives reclassified from accumulated OCI to income was less than $1 million, respectively, and was recorded in derivative loss (gain).

LG&E manages the price risk of its estimated future excess economic generation capacity using market-traded forward contracts. Hedge accounting treatment has not been elected for these transactions, and therefore gains and losses are shown in the statements of income.

The following tables present the effect of derivatives not designated as hedging instruments on income for the three- and six- months ended June 30:

(in millions)	Location of (Gain) Loss Recognized in Income on Derivatives	Amount of (Gain) Loss Recognized in Income on Derivatives	
		Three Months Ended June 30, 2010	Three Months Ended June 30, 2009
Energy trading and risk management contracts (realized)	Electric revenues	$ (1)	$ (3)
Energy trading and risk management contracts (unrealized)	Electric revenues	1	-
Interest rate swaps (realized)	Derivative loss (gain)	1	-
Interest rate swaps (unrealized)	Derivative loss (gain)	9	(11)
Total		$ 10	$ (14)

(in millions)	Location of (Gain) Loss Recognized in Income on Derivatives	Amount of (Gain) Loss Recognized in Income on Derivatives	
		Six Months Ended June 30, 2010	Six Months Ended June 30, 2009
Energy trading and risk management contracts (realized)	Electric revenues	$ (2)	$ (4)
Energy trading and risk management contracts (unrealized)	Electric revenues	(1)	(2)
Interest rate swaps (realized)	Derivative loss (gain)	1	1
Interest rate swaps (unrealized)	Derivative loss (gain)	10	(17)
Total		$ 8	$ (22)

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 for the three and six months ended June 30. The tables include the costs associated with both LG&E employees and E.ON U.S. Services employees who are providing services to the Company. The E.ON U.S. Services costs that are allocated to LG&E are approximately 43% and 44% of E.ON U.S. Services costs for June 30, 2010 and 2009, respectively.

Pension Benefits
Three Months Ended June 30,

(in millions)	2010			2009		
	LG&E	E.ON U.S. Services Allocation to LG&E	Total LG&E	LG&E	E.ON U.S. Services Allocation to LG&E	Total LG&E
Service cost	$ 1	$ 1	$ 2	$ 1	$ 1	$ 2
Interest cost	7	1	8	6	2	8
Expected return on plan assets	(7)	(1)	(8)	(5)	(1)	(6)
Amortization of service costs	2	-	2	2	-	2
Amortization of actuarial loss	2	1	3	3	1	4
Benefit cost	$ 5	$ 2	$ 7	$ 7	$ 3	$ 10

Other Postretirement Benefits
Three Months Ended June 30,

(in millions)	2010			2009		
	LG&E	E.ON U.S. Services Allocation to LG&E (a)	Total LG&E	LG&E	E.ON U.S. Services Allocation to LG&E (a)	Total LG&E
Service cost	$ 1	$ -	$ 1	$ -	$ -	$ -
Interest cost	1	-	1	1	-	1
Amortization of service costs	-	-	-	1	-	1
Benefit cost	$ 2	$ -	$ 2	$ 2	$ -	$ 2

(a) amounts are less than $1 million

(in millions)	Pension Benefits Six Months Ended June 30, 2010			2009		
	LG&E	E.ON U.S. Services Allocation to LG&E	Total LG&E	LG&E	E.ON U.S. Services Allocation to LG&E	Total LG&E
Service cost	$ 2	$ 2	$ 4	$ 2	$ 2	$ 4
Interest cost	13	3	16	13	3	16
Expected return on plan assets	(13)	(2)	(15)	(11)	(2)	(13)
Amortization of service costs	3	-	3	3	1	4
Amortization of actuarial loss	5	1	6	6	1	7
Benefit cost	$ 10	$ 4	$ 14	$ 13	$ 5	$ 18

(in millions)	Other Postretirement Benefits Six Months Ended June 30, 2010			2009		
	LG&E	E.ON U.S. Services Allocation to LG&E (a)	Total LG&E	LG&E	E.ON U.S. Services Allocation to LG&E	Total LG&E
Service cost	$ 1	$ -	$ 1	$ -	$ 1	$ 1
Interest cost	2	-	2	3	-	3
Amortization of service costs	1	-	1	1	-	1
Benefit cost	$ 4	$ -	$ 4	$ 4	$ 1	$ 5

(a) amounts are less than $1 million

In January 2010, LG&E and E.ON U.S. Services made a pension plan contribution of $20 million and $9 million, respectively. LG&E's intent is to fund the pension plan in a manner consistent with the requirements of the Pension Protection Act of 2006.

In 2010, LG&E has made contributions to other postretirement benefit plans totaling $3 million. The Company also anticipates further funding to match the annual postretirement expense and funding the 401(h) plan up to the maximum amount allowed by law.

Health Care Reform

In March 2010, Health Care Reform (the Patient Protection and Affordable Care Act of 2010) was signed into law. Many provisions of Health Care Reform do not take effect for an extended period of time, and many aspects of the law which are currently unclear or undefined will likely be clarified in future regulations.

Specific provisions within Health Care Reform that may impact LG&E include:

- Beginning in 2011, a requirement to extend dependent coverage up to age 26.
- Beginning in 2018, a potential excise tax on high-cost plans providing health coverage that exceeds certain thresholds.

LG&E continues to evaluate all implications of Health Care Reform on its benefit programs but at this time cannot predict the significance of those implications.

Note 5 - 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 LG&E, 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. The Company also files income tax returns in various state jurisdictions. While 2006 and later years are open under the federal statute of limitations, Revenue Agent Reports for 2006-2008 have been received from the IRS, effectively closing these years to additional audit adjustments. Tax years 2007 and 2008 were examined under an IRS pilot program named "Compliance Assurance Process" ("CAP"). This program accelerates the IRS' review to begin during the year applicable to the return and ends 90 days after the return is filed. Adjustments for 2007, agreed to and recorded in January 2009, were comprised of $5 million of depreciation-related differences. For 2008, the IRS allowed additional deductions in connection with the Company's application for a change in repair deductions and disallowed some of the bonus depreciation claimed on the original return. The net temporary tax impact for the Company was $13 million, and has been recorded in the second quarter of 2010. Tax years 2009 and 2010 are also being examined under CAP. No material items have been raised by the IRS at this time.

Additions and reductions of uncertain tax positions during 2010 and 2009 were less than $1 million. Possible amounts of uncertain tax positions for LG&E 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. If recognized, the less than $1 million of unrecognized tax benefits would reduce the effective income tax rate.

The amount LG&E recognized as interest expense and interest accrued related to unrecognized tax benefits was less than $1 million as of June 30, 2010 and December 31, 2009. The interest expense and interest accrued is based on IRS and Kentucky Department of Revenue large corporate interest rates for underpayment of taxes. At the date of adoption, the Company accrued less than $1 million in interest expense on uncertain tax positions. LG&E records the interest as interest expense and penalties as operating expenses in the income statement and accrued expenses in the balance sheet, on a pre-tax basis. No penalties were accrued by the Company through June 30, 2010.

In June 2006, LG&E and KU 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 LG&E was selected to receive $24 million in tax credits. A final IRS certification required to obtain the investment tax credits was received in August 2007. In September 2007, LG&E received an Order from the Kentucky Commission approving the accounting of the investment tax credits, which includes a full depreciation basis adjustment for the amount of the credits. Based on eligible construction expenditures incurred, LG&E recorded investment tax credits of $1 million and $2 million during the three and six months ended June 30, 2009, decreasing current federal income taxes. As of December 31, 2009, LG&E had recorded its maximum credit of $24 million. The income tax expense impact from amortizing these credits over the life of the related property will begin when the facility is placed in service. As of June 30, 2010, TC2 has not been 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. During 2008 and 2009, the plaintiffs submitted amended complaints alleging additional claims for relief and seeking a preliminary injunction to implement certain elements of the requested relief. In July 2010, the court denied the plaintiffs' motion for preliminary injunction. A motion by the Federal government to dismiss the amended complaint is currently pending. The Company is not a party to this proceeding and is not able to predict the ultimate outcome of this matter.

A reconciliation of differences between LG&E's income tax expense at the statutory U.S. federal income tax rate and LG&E's actual income tax expense for the three and six month periods ended June 30 follows:

	Three Months Ended June 30,		Six Months Ended June 30,	
(in millions)	2010	2009	2010	2009
Statutory federal income tax expense	$ 7	$ 12	$ 25	$ 13
State income taxes, net of federal benefit	1	1	2	1
Qualified production activities deduction	-	-	(1)	-
Amortization of investment tax credits	(1)	(1)	(1)	(2)
Income tax expense	$ 7	$ 12	$ 25	$ 12
Effective income tax rate	33.3%	36.4%	34.7%	31.6%

The amounts shown in the table above are rounded to the nearest $1 million; however, the effective income tax rates are based on actual underlying amounts.

Note 6 - Short-Term and Long-Term Debt

LG&E's long-term debt includes $120 million of pollution control bonds that are classified as current portion of long-term bonds 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 Jefferson County 2001 Series A and B and Trimble County 2001 Series A and B. Maturity dates for these bonds range from 2026 to 2027. The average annualized interest rate for these bonds during the three and six months ended June 30, 2010, was 0.92% and 0.81%, respectively. The average annualized interest rate for these bonds during the three and six months ended June 30, 2009, was 0.88% and 1.15%, respectively.

Pollution control bonds are obligations of LG&E issued in connection with tax-exempt pollution control revenue bonds issued by various governmental entities, principally counties in Kentucky.

A loan agreement obligates the Company to make debt service payments to the governmental entities that equate to the debt service due from the entities on the related pollution control revenue bonds. The loan agreement is an unsecured obligation of the Company. Debt issuance expense is capitalized in either regulatory assets or current or long-term other assets and amortized over the lives of the related bond issues, consistent with regulatory practices.

Several of the LG&E pollution control bonds are insured by monoline bond insurers whose ratings have been reduced due to exposures relating to insurance of sub-prime mortgages. At June 30, 2010, LG&E had an aggregate $574 million (including $163 million of reacquired bonds) of outstanding pollution control indebtedness, of which $135 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. During 2008, the Company experienced “failed auctions” when there were insufficient bids for the bonds. When a failed auction occurs, the interest rate is set pursuant to a formula stipulated in the indenture. During the three months ended June 30, 2010 and 2009, the average rate on the auction rate bonds was 0.55% and 0.42%, respectively. During the six months ended June 30, 2010 and 2009, the average rate on the auction rate bonds was 0.41% and 0.44%, respectively. The instruments governing these auction rate bonds permit LG&E 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 June 2009, S&P downgraded the credit rating of Ambac, an insurer of the Company’s bonds, from “A” to “BBB”. As a result, S&P downgraded the ratings on the Trimble County 2000 Series A, 2002 Series A and 2007 Series A; Jefferson County 2001 Series A; and Louisville Metro 2007 Series B bonds from “A” to “BBB+” in June 2009. The S&P ratings of these bonds are now based on the rating of the Company rather than the rating of Ambac since the Company’s rating is higher.

During 2008, LG&E converted several series of its pollution control bonds from the auction rate mode to a weekly interest rate mode, as permitted under the loan documents. In connection with these conversions, the Company purchased the bonds from the remarketing agent. As of June 30, 2010, the Company continued to hold repurchased bonds in the amount of $163 million. The other repurchased bonds were remarketed during 2008 in an intermediate-term fixed rate mode wherein the interest rate is reset periodically (every three to five years). LG&E will hold some or all of such repurchased bonds until a later date, at which time it may refinance, remarket or further convert such bonds. Uncertainty in markets relating to auction rate securities or steps the Company has taken or may take to mitigate such uncertainty, such as additional conversion, subsequent restructuring or redemption and refinancing, could result in increased interest expense, transaction expenses or other costs and fees or experiencing reduced liquidity relating to existing or future pollution control financing structures.

The Company participates in an intercompany money pool agreement wherein E.ON U.S. and/or KU make funds available to LG&E 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
June 30, 2010	$ 400	$ 137	$ 263	0.34%
December 31, 2009	$ 400	$ 170	$ 230	0.20%

E.ON U.S. maintains revolving credit facilities totaling $313 million at June 30, 2010 and December 31, 2009, to ensure funding availability for the money pool. At June 30, 2010, 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 balances are as follows:

($ in millions)	Total Available	Amount Outstanding	Balance Available	Average Interest Rate
June 30, 2010	$ 313	$ 244	$ 69	1.51%
December 31, 2009	$ 313	$ 276	$ 37	1.25%

As of June 30, 2010, the Company maintained bilateral lines of credit with unaffiliated financial institutions totaling $125 million which mature in June 2012. At June 30, 2010, there was no balance outstanding under any of these facilities.

There were no redemptions or issuances of long-term debt year-to-date through June 30, 2010. LG&E was in compliance with all debt covenants at June 30, 2010 and December 31, 2009.

See Note 2, Rates and Regulatory Matters, for certain debt refinancing and associated transactions which are anticipated by LG&E in connection with the PPL acquisition.

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 the Company's Annual Report for the year ended December 31, 2009 (including, but not limited to Notes 2, 9 and 14 to the financial statements of LG&E contained therein). See the Company's Annual Report regarding such commitments or contingencies.

Letters of Credit. LG&E has provided letters of credit as of June 30, 2010 and December 31, 2009, for off-balance sheet obligations totaling $3 million to support certain obligations related to landfill reclamation and a letter of credit for off-balance sheet obligations totaling less than $1 million to support certain obligations related to workers' compensation.

Construction Program. LG&E had approximately $50 million of commitments in connection with its construction program at June 30, 2010.

In June 2006, LG&E and KU 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. During 2009 and 2010, LG&E and KU have received several contractual notices from the TC2 construction contractor asserting historical force majeure and excusable event claims for a number of adjustments to the contract price, construction schedule, commercial operations date, liquidated damages or other relevant provisions. Further, during commissioning and testing activity conducted in the second quarter of 2010, the TC2 unit experienced burner malfunctions which have delayed the completion of commissioning and consequently the commercial operation date beyond the previously anticipated date of mid-June 2010. The Companies and the contractor are actively investigating the potential causes of and solutions to this development and currently estimate that commercial operation may be delayed until October 2010. The parties are continuing to discuss the existing force majeure, excusable delay and the recent burner malfunction issues and are attempting to resolve certain of them via settlement negotiations. The Company cannot currently estimate the ultimate outcome of these matters, including the extent, if any, that such outcome may result in materially increased costs for the construction of TC2, further changes in the TC2 construction completion or commercial operation dates or potential effects on levels of power purchases or wholesale sales due to such changed dates.

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. In September 2007, the Secretary of the Kentucky Environmental and Public Protection Cabinet issued a final Order upholding the permit. The environmental groups petitioned the EPA to object to the state permit and subsequent permit revisions. In determinations made in September 2008 and June 2009, the EPA rejected most of the environmental groups' claims but identified three permit deficiencies which the KDAQ addressed by revising the permit. In August 2009, the EPA issued an Order denying the remaining claims with the exception of two additional deficiencies which the KDAQ was directed to address. The EPA determined that the proposed permit subsequently issued by the KDAQ satisfied the conditions of the EPA Order although the agency recommended certain enhancements to the administrative record. In January 2010, the KDAQ issued a final permit revision incorporating the proposed changes to address the EPA objections. In March 2010, the environmental groups submitted a petition to the EPA to object to the permit revision, which is now pending before the EPA. The Company believes that the final permit as revised should not have a material adverse effect on its financial condition or results of operations. However, until the EPA issues a final ruling on the pending petition and all applicable appeals have been exhausted, the Company cannot predict the final outcome of this matter.

Thermostat Replacement. During January 2010, LG&E and KU announced a voluntary plan to replace certain thermostats, which had been provided to customers as part of the Companies' demand reduction programs, due to concerns that the thermostats may present a safety hazard. Under the plan, the Companies have replaced approximately 85% of the estimated 14,000 thermostats that need to be replaced. Total estimated costs associated with the replacement program are $2 million. However, the Companies cannot fully predict the ultimate outcome of the replacement program or other effects or developments which may be associated with the thermostat replacement matter at this time.

Environmental Matters. The Company's operations are subject to a number of environmental laws and regulations, 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 LG&E'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.

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 place in the interim. The remand of the CAIR results in some uncertainty with respect to certain other EPA or state programs and proceedings and the Companies' compliance plans relating thereto due to the interconnection of the CAIR with such associated programs.

In July 2010, the EPA issued the proposed CATR, which serves to replace the CAIR. The CATR provides for a two-phase SO_2 reduction program with Phase I reductions due by 2012, and Phase II reductions due by 2014. The CATR provides for NOx reductions in 2012, but the EPA advised that it is studying whether additional NOx reductions should be required for 2014. The CATR is more stringent than the CAIR as it accelerates certain compliance dates and provides for only intrastate and limited interstate trading of emission allowances. In addition to its preferred approach, the EPA is seeking comment on an alternative approach which would provide for individual emission limits at each power plant. The EPA has announced that it will propose additional "transport" rules to address compliance with revised NAAQS standards for ozone and particulate matter which will be issued by the EPA in the future, as discussed below. At present, LG&E is not able to predict the outcomes of the legal and regulatory proceedings related to the CATR; however, such outcomes, while not yet determinable, could result in significant costs to the Company.

In January 2010, the EPA proposed a revised NAAQS for ozone which would increase the stringency of the standard. In addition, the EPA published final revised NAAQS standards for nitrogen dioxide ("NO_2") and SO_2 in February 2010 and June 2010, respectively, which are more stringent than previous standards. Depending on the level of action determined necessary to bring local nonattainment areas into compliance with the revised NAAQS standards, LG&E's power plants are potentially subject to requirements for additional reductions in SO_2 and NOx emissions. Until such time as the relevant regulatory agencies make nonattainment designations and determine reductions required from local emissions sources, the Company is unable to determine what, if any, additional requirements may be imposed to achieve compliance with the revised NAAQS standards.

The costs to implement the respective proposed or final more stringent ozone, NO_2, SO_2, particulate matter or other standards under the NAAQS or CATR are not currently determinable. Depending upon whether the final rules or implementation methods incorporate additional emissions reduction requirements and the amounts of such reductions, such costs could be significant.

Hazardous Air Pollutants. As provided in 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 addition, in 2006, the Metro Louisville Air Pollution Control District adopted rules aimed at regulating additional hazardous air pollutants from sources including power plants.

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 rules with different or more stringent requirements for reduction of mercury and other hazardous air pollutants. Kentucky has also repealed its corresponding state mercury regulations. At present, LG&E 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. If the new rules are more stringent and require additional reductions in emissions, the costs to achieve such reductions, while not yet determinable, could be significant.

Acid Rain Program. 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 Clean Air Act also contains 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 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 the 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. LG&E had previously installed FGD equipment on all of its generating units prior to the effective date of the acid rain program. LG&E's strategy for its Phase II SO_2 requirements, which commenced in 2000, is to use accumulated emission allowances to defer additional capital expenditures and continue to evaluate improvements to further reduce SO_2 emissions. In order to achieve the NOx emission reductions mandated by the NOx SIP Call, LG&E installed additional NOx controls, including SCR technology, during the 2000 through 2009 time period at a cost of $197 million. In 2001, the Kentucky Commission granted approval to recover the costs incurred by LG&E for these projects through the ECR mechanism. Such monthly recovery is subject to periodic review by the Kentucky Commission.

In order to achieve mandated emissions reductions, LG&E expects to incur additional capital expenditures totaling approximately $140 million during the 2010 through 2012 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. LG&E believes its costs in reducing SO_2, NOx and mercury emissions to be comparable to those of similarly situated utilities with like generation assets. LG&E'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. LG&E 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.

GHG Developments. 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. As discussed below, 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, 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. The current administration has announced its support for the adoption of mandatory GHG reduction requirements at the federal level. The United States and other countries met in Copenhagen, Denmark in December 2009, in an effort to negotiate a GHG reduction treaty to succeed the Kyoto Protocol, which is set to expire in 2013. In Copenhagen, the U.S. made a nonbinding commitment to, among other things, seek to reduce GHG emissions to 17% below 2005 levels by 2020 and provide financial support to developing countries. The United States and other nations are scheduled to meet in Cancun, Mexico in late 2010 to continue negotiations toward a binding agreement.

GHG Legislation. LG&E is monitoring on-going efforts to enact GHG reduction requirements and requirements governing carbon sequestration at the state and federal level and is assessing potential impacts of such programs and strategies to mitigate those impacts. In June 2009, the U.S. House of Representatives passed the American Clean Energy and Security Act of 2009, which is a comprehensive energy bill containing the first-ever nation-wide GHG cap and trade program. The bill would provide for reductions in GHG emissions of 3% below 2005 levels by 2012, 17% by 2020 and 83% by 2050. In order to cushion potential rate impacts for utility customers, approximately 43% of emissions allowances would initially be allocated at no cost to the electric utility sector, with this allocation gradually declining to 7% in 2029 and zero thereafter. The bill would also establish a renewable electricity standard requiring utilities to meet 20% of their electricity demand through renewable energy and energy efficiency by 2020. The bill contains additional provisions regarding carbon capture and sequestration, clean transportation, smart grid advancement, nuclear and advanced technologies and energy efficiency.

In September 2009, the Clean Energy Jobs and American Power Act, which is largely patterned on the House legislation, was introduced in the U.S. Senate. The Senate bill raises the emissions reduction target for 2020 to 20% below 2005 levels and does not include a renewable electricity standard. While the initial bill lacked detailed provisions for the allocation of emissions allowances, a subsequent revision incorporated allowance allocation provisions similar to the House bill. In 2010, Senators Kerry and Lieberman and others have undertaken additional work to draft GHG legislation but have introduced no bill in the Senate to date. In July 2010, Senate Majority Leader Reid announced that he did not anticipate that GHG legislation would be brought to the Senate floor in the current session. The Company is closely monitoring the progress of pending energy legislation, but the prospect for passage of comprehensive GHG legislation in 2010 is uncertain.

GHG Regulations. In April 2007, the U.S. Supreme Court ruled that the EPA has the authority to regulate GHG under the Clean Air Act. In April 2009, the EPA issued a proposed endangerment finding concluding that GHGs endanger public health and welfare, which is an initial rulemaking step under the Clean Air Act. A final endangerment finding was issued in December 2009. In September 2009, the EPA issued a final GHG reporting rule requiring reporting by facilities with annual GHG emissions equivalent to at least 25,000 tons of carbon dioxide. A number of the Company's facilities will be required to submit annual reports commencing with calendar year 2010. In May 2010, the EPA issued a final GHG "tailoring" rule requiring new or modified sources with GHG emissions equivalent to at least 75,000 tons of carbon dioxide to obtain permits under the Prevention of Significant Deterioration Program. Such new or modified facilities would be required to install Best Available Control Technology. While the Company is unaware of any currently available GHG control technology that might be required for installation on new or modified power plants, it is currently assessing the potential impact of the rule. The final rule will apply to new and modified power plants beginning in January 2011.

The Company is unable to predict whether mandatory GHG reduction requirements will ultimately be enacted through legislation or regulations.

GHG Litigation. A number of lawsuits have been filed asserting common law claims including nuisance, trespass and negligence against various companies with GHG emitting facilities. In October 2009, a three-judge panel of the United States Court of Appeals for the 5th Circuit in the case of Comer v. Murphy Oil reversed a lower court, holding that private plaintiffs have standing to assert certain common law claims against more than 30 utility, oil, coal and chemical companies. In March 2010, the court vacated the opinion of the three-judge panel and granted a motion for rehearing but subsequently denied the appeal due to the lack of a quorum. The appellate ruling leaves in effect the lower court ruling dismissing the plaintiffs' claims. The Comer complaint alleges that GHG emissions from the defendants' facilities contributed to global warming which increased the intensity of Hurricane Katrina. E.ON, the indirect parent of LG&E and KU was included as defendant in the complaint but has not been subject to the proceedings due to the failure of the plaintiffs to pursue service under the applicable international procedures. LG&E and KU are currently unable to predict further developments in the Comer case. LG&E and KU continue to monitor relevant GHG litigation to identify judicial developments that may be potentially relevant to their operations.

Ash Ponds, Coal-Combustion Byproducts and Water Discharges. The EPA has undertaken various initiatives in response to the December 2008 impoundment failure at the Tennessee Valley Authority's Kingston power plant, which resulted in a major release of coal combustion byproducts into the environment. The EPA issued information requests to utilities throughout the country, including LG&E, to obtain information on their ash ponds and other impoundments. In addition, the EPA inspected a large number of impoundments located at power plants to determine their structural integrity. The inspections included several of LG&E's impoundments, which the EPA found to be in satisfactory condition except for certain impoundments at the Mill Creek and Cane Run stations, which were determined to be in fair condition. In June 2010, the EPA published proposed regulations for coal combustion byproducts handled in landfills and ash ponds. The EPA has proposed two alternatives: (1) regulation of coal combustion byproducts in landfills and ash ponds as a hazardous waste or (2) regulation of coal combustion byproducts as a solid waste with minimum national standards. Under both alternatives, the EPA has proposed safety requirements to address the structural integrity of ash ponds. In addition, the EPA will consider potential refinements of the provisions for beneficial reuse of coal combustion byproducts. The EPA has also announced plans to develop revised effluent limitations guidelines and standards governing discharges from power plants. The Company is monitoring these ongoing regulatory developments but will be unable to determine the impact until such time as new rules are finalized. Should the final rules require more stringent storage or disposal practices for these byproducts than currently in place or indirectly cause changes in other operational or generation practices, the costs of such revised practices, while not yet determinable, could be significant.

In May 2010, the Kentucky Waterways Alliance and other environmental groups filed a petition with the Kentucky Energy and Environment Cabinet challenging the Kentucky Pollutant Discharge Elimination System permit issued in April 2010, which covers water discharges from the Trimble County Station. Due to the preliminary stage of the proceedings, the Company is currently unable to predict the outcome or precise impact of this matter.

As a company with significant coal-fired generating assets, LG&E could be substantially impacted by pending or future environmental rules or legislation requiring mandatory reductions in GHG emissions or other air emissions, imposing more stringent standards on discharges to waterways, or establishing additional requirements for handling or disposal of coal combustion byproducts. However, the precise impact on its operations, including the reduction targets and deadlines that would be applicable, cannot be determined prior to the finalization of such requirements. While the Company believes that many costs of complying with such pending or future requirements would likely be recoverable under the ECR or other potential cost-recovery mechanisms, this cannot be assured.

General Environmental Proceedings. From time to time, LG&E 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 a prior Section 114 information request from the EPA relating to new source review issues at LG&E's Mill Creek and TC1 generation units; remediation obligations or activities for former manufactured gas plant sites or elevated Polychlorinated Biphenyl levels at existing properties; liability under the Comprehensive Environmental Response, Compensation and Liability Act for cleanup at various off-site waste sites; and on-going claims regarding alleged particulate emissions from the Company's Cane Run station and claims regarding GHG emissions from the Company's generating stations. With respect to the former manufactured gas plant sites, LG&E has estimated that it could incur additional costs of less than $1 million for remaining clean-up activities under existing approved plans or agreements. Based on analysis to date, the resolution of these matters is not expected to have a material impact on the Company's operations.

Note 8 - Segments of Business

LG&E's revenues, net income and total assets by business segment for the three and six months ended June 30, were as follows:

(in millions)	Three Months Ended June 30, 2010	Three Months Ended June 30, 2009	Six Months Ended June 30, 2010	Six Months Ended June 30, 2009
LG&E Electric				
Gross/net revenues	$ 247	$ 228	$ 479	$ 463
Net income	17	21	33	15
Total assets	2,859	2,788	2,859	2,788
LG&E Gas				
Gross revenues	$ 34	$ 51	$ 169	$ 246
Intersegment revenues (a)	(2)	(2)	(3)	(4)
Net revenues	$ 32	$ 49	$ 166	$ 242
Net income	(3)	-	14	11
Total assets	657	685	657	685
Total				
Gross revenues	$ 281	$ 279	$ 648	$ 709
Intersegment revenues (a)	(2)	(2)	(3)	(4)
Net revenues	$ 279	$ 277	$ 645	$ 705
Net income	14	21	47	26
Total assets	3,516	3,473	3,516	3,473

(a) Intersegment revenues are eliminated upon consolidation of the LG&E Electric and LG&E Gas segments.

Note 9 - Related Party Transactions

LG&E, subsidiaries of E.ON U.S. and subsidiaries of E.ON engage in related party transactions. Transactions between LG&E and E.ON U.S. subsidiaries are eliminated upon consolidation of E.ON U.S. Transactions between LG&E and E.ON subsidiaries are eliminated upon consolidation of E.ON. These transactions are generally performed at cost and are in accordance with FERC regulations under the Public Utility Holding Company Act of 2005 and the applicable Kentucky Commission regulations. The significant related party transactions are disclosed below.

Electric Purchases

LG&E and KU 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 electric operating revenues, power purchased expenses and other operation and maintenance expenses. LG&E's intercompany electric revenues and power purchased expense for the three and six months ended June 30, were as follows:

	Three Months Ended June 30,		Six Months Ended June 30,	
(in millions)	2010	2009	2010	2009
Electric operating revenues from KU	$ 23	$ 28	$ 48	$ 59
Power purchased from KU	3	5	10	16

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.

LG&E's interest expense to affiliated companies for the three and six months ended June 30 was as follows:

	Three Months Ended June 30,		Six Months Ended June 30,	
(in millions)	2010	2009	2010	2009
Interest on Fidelia loans	$ 6	$ 6	$ 13	$ 13

Interest expense paid to E.ON U.S. on the money pool arrangement was less than $1 million for the three and six months ended June 30, 2010 and 2009.

Other Intercompany Billings

E.ON U.S. Services provides the Company 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 LG&E, labor and burdens of E.ON U.S. Services employees performing services for LG&E, coal purchases and other vouchers paid by E.ON U.S. Services on behalf of LG&E. The cost of these services is directly charged to the Company, 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, LG&E and KU provide services to each other and to E.ON U.S. Services. Billings between LG&E and KU relate to labor and overheads associated with union and hourly employees performing work for the other utility, charges related to jointly-owned generating units and other miscellaneous charges. Billings from LG&E to E.ON U.S. Services include cash received by E.ON U.S. Services on behalf of LG&E, primarily tax settlements, and other payments made by the Company on behalf of other non-regulated businesses which are reimbursed through E.ON U.S. Services.

Intercompany billings to and from LG&E for the three and six months ended June 30, were as follows:

	Three Months Ended June 30,		Six Months Ended June 30,	
(in millions)	2010	2009	2010	2009
E.ON U.S. Services billings to LG&E	$ 59	$ 52	$ 115	$ 95
LG&E billings to KU	12	-	19	-
KU billings to LG&E	1	36	1	47
LG&E billings to E.ON U.S. Services	-	-	5	-

In March 2010, the Company paid dividends of $30 million to its common shareholder, E.ON U.S. In March and June 2009, LG&E paid dividends of $35 million and $45 million, respectively, to its common shareholder, E.ON U.S.

Intercompany Balances

The Company had the following balances with its affiliates as of June 30, 2010 and December 31, 2009:

(in millions)	June 30, 2010	December 31, 2009
Accounts receivable from KU	$ 18	$ 53
Accounts payable to E.ON U.S. Services	11	18
Accounts payable to E.ON U.S.	11	4
Accounts payable to Fidelia	6	6
Notes payable to E.ON U.S.	137	170
Long-term debt to Fidelia	485	485

Note 10 - Subsequent Events

Subsequent events have been evaluated through August 11, 2010, the date of issuance of these statements, and these statements contain all necessary adjustments and disclosures resulting from that evaluation.

On July 30, 2010, the Kentucky Commission issued an Order in the current base rate cases approving all the provisions in the stipulation, with rates effective for service rendered on and after August 1, 2010.

Management's Discussion and Analysis

Overview

LG&E, incorporated in Kentucky in 1913, is a regulated public utility engaged in the generation, transmission, distribution and sale of electric energy and the storage, distribution and sale of natural gas. LG&E provides electric service to approximately 397,000 customers in Louisville and adjacent areas in Kentucky covering approximately 700 square miles in 9 counties. Natural gas service is provided to approximately 321,000 customers in its electric service area and 8 additional counties in Kentucky. Approximately 95% of the electricity generated by LG&E is produced by its coal-fired electric generating stations, all equipped with systems to reduce SO_2 emissions. The remainder is generated by a hydroelectric power plant and natural gas and oil fueled combustion turbines. Underground natural gas storage fields help LG&E provide economical and reliable natural gas service to customers.

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

The following discussion and analysis by management focuses on those factors that had a material effect on LG&E's financial results of operations and financial condition during the three- and six-month periods ended June 30, 2010, and should be read in connection with the condensed financial statements and notes thereto and the Annual Report for the year ending December 31, 2009. Dollars are in millions, unless otherwise noted.

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, 2009.

PPL Acquisition

On April 28, 2010, E.ON U.S. announced that a Purchase and Sale Agreement (the "Agreement") had been entered into among E.ON US Investments, PPL and E.ON.

The Agreement provides for the sale of E.ON U.S. to PPL. Pursuant to the Agreement, at closing, PPL will acquire all of the outstanding limited liability company interests of E.ON U.S. for cash consideration of $2.1 billion. In addition, pursuant to the Agreement, PPL agreed to assume $925 million of pollution control bonds and to repay indebtedness owed by E.ON U.S. and its subsidiaries to E.ON US Investments and its affiliates. Such affiliate indebtedness is currently estimated to be $4.6 billion. The aggregate consideration payable by PPL on closing, $7.6 billion (including the assumed indebtedness), is subject to adjustment for specified incremental investment in E.ON U.S. that will potentially be made by E.ON US Investments and its affiliates prior to closing.

The transaction is subject to customary closing conditions, including the expiration or termination of the applicable waiting period under the Hart-Scott-Rodino Act, receipt of required regulatory approvals (including state regulators in Kentucky, Virginia and Tennessee, and the FERC) and the absence of injunctions or restraints imposed by governmental entities. Subject to receipt of required approvals, the transaction is expected to close by the end of 2010. Change of control and financing-related applications were filed on May 28, 2010, with the Kentucky Commission and on June 15, 2010, with the Virginia Commission and the Tennessee Regulatory Authority. An application with the FERC was filed on June 28, 2010. During the second quarter of 2010, a number of intervenors made entries into the Kentucky Commission proceedings and data request filings and responses occurred. Hearings in the Kentucky Commission proceedings are scheduled for September 8, 2010. Early termination of the final Hart-Scott-Rodino waiting period was received on August 2, 2010.

Based upon credit and financial market conditions, the anticipated PPL acquisition and other factors, the Company anticipates completing certain re-financing transactions and, where applicable, has applied for regulatory approvals for such transactions. LG&E anticipates issuing up to $535 million in public first mortgage bonds, the proceeds of which will substantially be used to refund existing long-term intercompany debt. As required by existing covenants, in connection with the issuance of any such secured debt, LG&E would also collateralize certain outstanding pollution control bond debt series which are presently unsecured. Upon such collateralization, approximately $574 million in existing pollution control debt would become secured debt, supported by a first mortgage lien. Subject to regulatory approvals and other conditions, LG&E may complete these transactions, in whole or in part, during late 2010 and early 2011.

See Note 6 of Notes to Condensed Financial Statements for further information regarding the refinancing, remarketing or conversion of existing pollution control debt.

Regulatory Matters

In January 2010, LG&E filed an application with the Kentucky Commission requesting an increase in electric base rates of approximately 12%, or $95 million annually, and its gas base rates of approximately 8%, or $23 million annually, including an 11.5% return on equity for electric and gas. LG&E requested the increase, based on the twelve month test year ended October 31, 2009, to become effective on and after March 1, 2010. The requested rates were suspended until August 1, 2010. A number of intervenors entered the rate case, including the Kentucky Attorney General's office, certain representatives of industrial and low-income groups and other third parties, and submitted filings challenging the Company's requested rate increases, in whole or in part. A hearing was held on June 8, 2010. LG&E and all of the intervenors except for the AG agreed to a stipulation providing for an increase in electric base rates of $74 million annually and gas base rates of $17 million annually and filed a request with the Kentucky Commission to approve such settlement. An Order in the proceeding was issued in July 2010, approving all the provisions in the stipulation, with rates effective on and after August 1, 2010.

In January 2009, a significant ice storm passed through LG&E's service territory causing approximately 205,000 customer outages and was followed closely by a severe wind storm in February 2009 that caused approximately 37,000 customer outages. LG&E incurred $44 million in incremental operation and maintenance expenses and $10 million in capital expenditures related to the restoration following the two storms. The Company filed an application with the

Kentucky Commission in April 2009, requesting approval to establish a regulatory asset and defer for future recovery approximately $45 million in incremental operation and maintenance expenses related to the storm restoration. In September 2009, the Kentucky Commission issued an Order allowing the Company to establish a regulatory asset of up to $45 million based on its actual costs for storm damages and service restoration due to the January and February 2009 storms. In September 2009, the Company established a regulatory asset of $44 million for actual costs incurred. The Company received approval in its current base rate cases to recover this asset over a ten year period beginning August 1, 2010.

Environmental Matters

General. Protection of the environment is a major priority for LG&E and a significant element of its business activities. LG&E's properties and operations are subject to extensive environmental-related oversight by federal, state and local regulatory agencies, including via air quality, water quality, waste management and similar laws and regulations. Therefore, LG&E must conduct its operations in accordance with numerous permit and other requirements issued under or contained in such laws or regulations.

Climate Change. Recent developments continue to indicate an increased possibility of significant climate change or GHG legislation or regulation, at the international, federal, regional and state levels. During December 2009, as part of the United Nation's Copenhagen Accord, the United States agreed to a non-binding goal to reduce GHG emissions to 17% below 2005 levels by 2020. Additionally, during 2009, the U.S. House of Representatives passed comprehensive GHG legislation, which included a number of measures to limit GHG emissions and achieve GHG emission reduction targets below 2005 levels of 3%, 17% and 83% by 2012, 2020 and 2050, respectively, and the U.S. Senate is considering companion legislation. In late 2009, the EPA issued or proposed various regulatory initiatives relating to GHG matters, including an endangerment finding relating to mobile sources of GHGs, a GHG reporting requirement and a rule relating to permitting requirements for new or modified GHG emission sources. Finally, a number of U.S. states, although not currently including Kentucky, have adopted GHG-reduction legislation or regulation of various sorts. The developing GHG initiatives include a number of differing structures and formats, including direct limitations on GHG sources, issuance of allowances for GHG emissions, cap-and-trade programs for such allowances, renewable or alternative generation portfolio standards and mechanisms relating to demand reduction, energy efficiency, smart-grid, transmission expansion, carbon-sequestration or other GHG-reducing efforts. While the final terms and impacts of such initiatives cannot be estimated, LG&E, as a primarily coal-fired utility, could be highly affected by such proceedings.

The cost to LG&E and the effect on LG&E's business of complying with potential GHG restrictions will depend upon the details of the programs ultimately enacted. Some of the design elements which may have the greatest effect on LG&E include (a) the required levels and timing of any carbon caps or limits, (b) the emission sources covered by such caps or limits, (c) transition and mitigation provisions, such as phase-in periods, free allowances or price caps, (d) the availability and pricing of relevant GHG-reduction technologies, goods or services and (e) economic, market and customer reaction to electricity price and demand changes due to GHG limits. While the costs to comply with future GHG developments are not currently determinable, such costs could be significant.

Ultimately, environmental matters or potential environmental matters can represent an important element of current or future potential capital requirements, future unit retirement or replacement decisions, supply and demand for electricity, operating and maintenance expenses or compliance risks for the Company. While LG&E currently anticipates that many of such direct costs or effects may be recoverable through rates or other regulatory mechanisms, particularly with respect to coal-related generation, the availability, timing or completeness of such rate recovery cannot be assured. Ultimately, climate change matters could result in material effects on LG&E's results of operations, liquidity and financial position. See Management's Discussion and Analysis and Note 7 of Notes to Condensed Financial Statements for additional information.

Results of Operations

The electric and gas 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 June 30, 2010, Compared to
Three Months Ended June 30, 2009

Net Income

Net income was $14 million for the three months ended June 30, 2010, compared to $21 million for the same period in 2009. The decrease was primarily the result of the following:

	Three Months Ended June 30, 2010	Three Months Ended June 30, 2009	Increase (Decrease)
Total operating revenues	$ 279	$ 277	2
Total operating expenses	236	244	(8)
Operating income	43	33	10
Derivative loss (gain)	10	(11)	21
Interest expense	5	4	1
Interest expense to affiliated companies	7	7	-
Income before income taxes	21	33	(12)
Income tax expense	7	12	(5)
Net income	$ 14	$ 21	$ (7)

Net income attributable by segment was:

	Three Months Ended June 30, 2010	Three Months Ended June 30, 2009	Increase (Decrease)
Electric	$ 17	$ 21	$ (4)
Gas	(3)	-	(3)
Total	$ 14	$ 21	$ (7)

Operating Revenues

Operating revenues for the three months ended June 30, follow:

	Three Months Ended June 30, 2010	Three Months Ended June 30, 2009	Increase (Decrease)
Electric	$ 247	$ 228	$ 19
Gas	32	49	(17)
Total operating revenues	$ 279	$ 277	$ 2

Electric Revenues

The $19 million increase in electric revenues in the three months ended June 30, 2010, was primarily due to:

	Increase (Decrease)
Retail sales volumes (a)	$ 17
Retail FAC costs billed to customers due to higher fuel costs	8
ECR surcharge due to increased recoverable capital spending	2
DSM revenue due to increased recoverable program spending	2
Wholesale sales to KU due to volume (b)	(4)
Wholesale sales to third parties due to volume (c)	(4)
Gains in energy marketing financial swaps	(2)
	$ 19

(a) Due to increased consumption by residential customers as a result of increased cooling degree days and higher energy usage by commercial and industrial customers as a result of improved economic conditions
(b) Primarily due to increased native load requirements in the second quarter of 2010. Via a mutual agreement, LG&E sells its lower cost electricity to KU to serve KU's native load and purchases KU's excess economic capacity to make wholesale sales.
(c) Primarily due to increased energy demand from industrial and residential customers and coal-fired generation unit outages during the second quarter of 2010.

Gas Revenues

The $17 million decrease in natural gas revenues in the three months ended June 30, 2010, was primarily due to:

	Increase (Decrease)
Retail sales volumes due to warmer temperatures	$ (11)
Retail average cost of gas billed through the GSC due to lower natural gas prices	(7)
WNA revenues	1
	$ (17)

Operating Expenses

Fuel for electric generation and natural gas supply expense comprise a large component of total operating expenses. Increases or decreases in the costs of fuel and natural gas supply are reflected in retail rates through the FAC and GSC, subject to the approval of the Kentucky Commission. Operating expenses for the three months ended June 30, follow:

	Three Months Ended June 30, 2010	Three Months Ended June 30, 2009	Increase (Decrease)
Fuel for electric generation	$ 90	$ 83	$ 7
Power purchased	12	14	(2)
Gas supply expenses	12	29	(17)
Other operation and maintenance expenses	87	84	3
Depreciation and amortization	35	34	1
Total operating expenses	$ 236	$ 244	$ (8)

Fuel for Electric Generation

The $7 million increase in fuel for electric generation in the three months ended June 30, 2010, was primarily due to:

	Increase (Decrease)
Commodity and transportation costs for coal and oil	$ 6
Fuel usage volumes	1
	$ 7

Power Purchased

The $2 million decrease in power purchased expense in the three months ended June 30, 2010, was primarily due to:

	Increase (Decrease)
Purchases from KU due to lower volume (a)	$ (3)
Prices for purchases used to serve retail customers	1
	$ (2)

(a) Via a mutual agreement, LG&E sells its lower cost electricity to KU to serve KU's native load. Decreased purchases due to increased demand by LG&E and KU native load customers and reduced availability of LG&E's lower cost generation to supply KU's demand, as a result of LG&E's unit outages

Gas Supply Expenses

The $17 million decrease in gas supply expenses in the three months ended June 30, 2010, was primarily due to:

	Increase (Decrease)
Cost of gas supply billed to customers	$ (9)
Natural gas volumes delivered to retail customers	(8)
	$ (17)

Other Operation and Maintenance Expenses

Other operation and maintenance expenses increased $3 million in the three months ended June 30, 2010, due to $2 million of increased other operation expenses and $1 million of increased maintenance expenses ($1 million).

Other Operation Expenses

The $2 million increase in other operation expenses in the three months ended June 30, 2010, was primarily due to:

	Increase (Decrease)
Transmission expense	$ 1
MISO RSG resettlements incurred in 2009	1
Administrative and general expense	1
Property and other taxes reduction resulting from an increased coal tax credit	(1)
	$ 2

Maintenance Expenses

The $1 million increase in maintenance expenses in the three months ended June 30, 2010 was primarily due to:

	Increase (Decrease)
Steam maintenance expense due to increased scheduled unit outages	$ 5
Distribution expense primarily due to additional winter storm restoration expenses recorded in 2009	(4)
	$ 1

Derivative Loss (Gain)

The $21 million increase in derivative loss (gain) in the three months ended June 30, 2010, was primarily due to a loss in 2010, versus a gain in 2009, from the change in the mark-to-market value of ineffective interest rate swaps. Gains on the ineffective interest rate swaps are due to rising interest rates and losses are due to declining interest rates.

Interest Expense

The $1 million increase in interest expense, including interest expense to affiliated companies, in the three months ended June 30, 2010, was primarily due to the ineffectiveness of the effective interest rate swap.

Income Tax Expense

See Note 5 of Notes to Condensed Financial Statements for a reconciliation of differences between the statutory U.S. federal income tax expense and LG&E's income tax expense.

Six Months Ended June 30, 2010, Compared to
Six Months Ended June 30, 2009

Net Income

Net income was $47 million for the six months ended June 30, 2010, compared with $26 million for the same period in 2009. The increase was primarily the result of the following:

	Six Months Ended June 30, 2010	2009	Increase (Decrease)
Total operating revenues	$ 645	$ 705	$ (60)
Total operating expenses	538	660	(122)
Operating income	107	45	62
Derivative loss (gain)	11	(16)	27
Other expense - net	1	1	-
Interest expense	9	8	1
Interest expense to affiliated companies	14	14	-
Income before income taxes	72	38	34
Income tax expense	25	12	13
Net income	$ 47	$ 26	$ 21

Net income attributable by segment was:

	Six Months Ended June 30, 2010	2009	Increase (Decrease)
Electric	$ 33	$ 15	$ 18
Gas	14	11	3
Total	$ 47	$ 26	$ 21

Operating Revenues

Operating revenues for the six months ended June 30 follow:

	Six Months Ended June 30, 2010	2009	Increase (Decrease)
Electric	$ 479	$ 463	$ 16
Gas	166	242	(76)
Total operating revenues	$ 645	$ 705	$ (60)

Electric Revenues

The $16 million increase in electric revenues in the six months ended June 30, 2010, was primarily due to:

	Increase (Decrease)
Retail sales volumes (a)	$ 26
FAC costs billed to customers due to higher fuel cost	5
DSM revenue due to increased recoverable program spending	5
Miscellaneous operating revenues including late payment charges	2
ECR surcharge due to increased recoverable capital spending	1
Wholesale sales to third parties due to spot market prices	1
Wholesale sales to KU due to volume (b)	(10)
Wholesale sales to third parties due to volume (c)	(7)
Gains in energy marketing financial swaps (d)	(3)
Retail base rates	(3)
Wholesale sales to KU due to fuel prices	(1)
	$ 16

(a) Due to increased consumption by residential customers as a result of increased cooling degree days and higher energy usage by industrial and commercial customers as a result of improved economic conditions.
(b) Primarily due to increased energy demand from industrial and residential customers and coal-fired generation outages during the first six months of 2010. Via a mutual agreement, LG&E sells its lower cost electricity to KU to serve KU's native load and purchases KU's excess economic capacity for LG&E to make wholesale sales.
(c) Primarily due to increased energy demand from industrial and residential customers and coal-fired generation unit outages during the first six months of 2010.
(d) Due to lower realized and unrealized gains, the buy-back of swap transactions and decreased trading activity in 2010.

Gas Revenues

The $76 million decrease in gas revenues in the six months ended June 30, 2010, was primarily due to:

	Increase (Decrease)
Retail average cost billed through GSC (a)	$ (88)
WNA revenues (b)	(3)
Retail sales volumes (c)	10
Retail base rates (d)	4
DSM revenues	1
	$ (76)

(a) Due to reductions in gas prices as a result of lower fuel costs

(b) Due to higher retail sales volumes during the first quarter resulting from increased total heating degree days.
(c) Due to colder temperatures in the first quarter of 2010 and increased usage by commercial and industrial customers as a result of improved economic conditions
(d) Due to the full period benefit of higher base rates resulting from the application of the base rate case settlement in February 2009

Operating Expenses

Fuel for electric generation and gas supply expenses comprise a large component of total operating expenses. Increases or decreases in the costs of fuel and gas supply are reflected in retail rates through the FAC and GSC, subject to the approval of the Kentucky Commission. Operating expenses for the six months ended June 30, follow:

	Six Months Ended June 30, 2010	Six Months Ended June 30, 2009	Increase (Decrease)
Fuel for electric generation	$ 173	$ 174	$ (1)
Power purchased	29	33	(4)
Gas supply expenses	93	179	(86)
Other operation and maintenance expenses	174	207	(33)
Depreciation and amortization	69	67	2
Total operating expenses	$ 538	$ 660	$ (122)

Fuel for Electric Generation

The $1 million decrease in fuel for electric generation in the six months ended June 30, 2010, was primarily due to:

	Increase (Decrease)
Fuel usage volumes	$ (3)
Commodity and transportation costs for oil	2
	$ (1)

Power Purchased

The $4 million decrease in power purchased expense in the six months ended June 30, 2010, was primarily due to:

	Increase (Decrease)
Purchases from KU due to lower volume (a)	$ (5)
Purchases from KU due to fuel costs (a)	(1)
Demand payments for third-party purchases	1
Prices for purchases used to serve retail customers	1
	$ (4)

(a) Via a mutual agreement, LG&E sells its lower cost electricity to KU to serve KU's native load. Decreased purchases due to increased demand by LG&E and KU native load customers and reduced availability of LG&E's lower cost generation to supply KU's demand, as a result of LG&E's unit outages. Sales and purchases between LG&E and KU are at cost.

Gas Supply Expenses

The $86 million decrease in gas supply expenses in the six months ended June 30, 2010, was primarily due to:

	Increase (Decrease)
Cost of gas supply billed to customers	$ (98)
Natural gas volumes delivered to retail customers	11
Wholesale sales	1
	$ (86)

Other Operation and Maintenance Expenses

Other operation and maintenance expenses decreased $33 million in the six months ended June 30, 2010, due to $34 million of decreased maintenance expenses and $1 million of increased other operation expenses.

Other Operation Expenses

The $1 million increase in other operation expenses was primarily due to:

	Increase (Decrease)
Transmission expense	$ 2
MISO RSG resettlements incurred in 2009	1
Administrative and general expense	1
Property and other taxes reduction resulting from an increased coal tax credit	(1)
Steam maintenance expense due to increased scheduled unit outages	(1)
Natural gas losses due to lower fuel usage and price	(1)
	$ 1

Maintenance Expenses

The $34 million decrease in maintenance expenses in the six months ended June 30, 2010, was primarily due to:

	Increase (Decrease)
Distribution expense incurred in 2009 due to winter storm restoration	$ (44)
Boiler and electric maintenance expense	9
Administrative and general expense	1
	$ (34)

Derivative Loss (Gain)

The $27 million increase in derivative loss (gain) in the six months ended June 30, 2010, was primarily due to a loss in 2010, versus a gain in 2009, from the change in the mark-to-market value of ineffective interest rate swaps. Gains on the ineffective interest rate swaps are due to rising interest rates and losses are due to declining interest rates.

Interest Expense

The $1 million increase in interest expense, including interest expense to affiliated companies, in the six months ended June 30, 2010, was primarily due to the ineffectiveness of the effective interest rate swap.

Income Tax Expense

See Note 5 of Notes to Condensed Financial Statements for a reconciliation of differences between the statutory U.S. federal income tax expense and LG&E's income tax expense.

Financial Condition

Liquidity and Capital Resources

(millions)	June 30, 2010	December 31, 2009
Cash and cash equivalents	$ 6	$ 5
Current portion of long-term bonds	120	120
Notes payable to affiliated company	137	170

The $1 million increase in LG&E's cash and cash equivalents in the six months ended June 30, 2010, was primarily the net result of:

	Increase (Decrease)
Cash provided by operating activities	$ 84
Proceeds from assets sold to affiliate	48
Construction expenditures	(68)
A net decrease in short-term borrowings from affiliated company	(33)
Payments of dividends	(30)
	$ 1

Working Capital Deficiency

As of June 30, 2010, LG&E had a working capital deficiency of $114 million, primarily due to short-term debt from affiliates associated with the repurchase of certain of its tax-exempt bonds totaling $163 million and $120 million of tax-exempt bonds which allow the investors to put the bonds back to the Company causing them to be classified as current portion of long-term bonds. The Company has adequate liquidity facilities to repurchase any bonds put back to the Company. The repurchased bonds are being held until they can be refinanced or restructured. Working capital deficiencies can be funded through an intercompany money pool agreement or through bilateral lines of credit. See Note 6 of Notes to Condensed Financial Statements. LG&E believes that its sources of funds will be sufficient to meet the needs of its business in the foreseeable future.

Auction Rate Securities

Auctions for auction rate securities issued by LG&E continue to fail during the quarter. LG&E held $163 million of its own auction rate securities at June 30, 2010 and December 31, 2009. See Note 6 of Notes to Condensed Financial Statements for further discussion of auction rate securities.

Debt

Regulatory approvals are required for LG&E to incur additional debt. The FERC authorizes the issuance of short-term debt while the Kentucky Commission authorizes the issuance of long-term debt. In November 2009, LG&E received a two-year authorization from the FERC to borrow up to $400 million in short-term funds. These short-term funds are made available via the

Company's participation in an intercompany money pool agreement wherein E.ON U.S. and/or KU make funds available to LG&E at market-based rates (based on highly rated commercial paper issues).

A significant portion of LG&E's short-term debt balance ($163 million) is for borrowings incurred to repurchase auction rate tax-exempt bonds. Following the repurchase, the auction rate tax-exempt bonds have been removed from the balance sheet. However, these bonds are being held until they can be refinanced or restructured.

See Note 6 of Notes to Condensed Financial Statements for information on redemptions, maturities and issuances of long-term debt.

Common Stock Dividends

In March 2010, the Company paid dividends of $30 million to its common shareholder, E.ON U.S. LG&E uses net cash generated from its operations and external financing (including financing from affiliates) to fund the payment of dividends. Future dividends, declared at the discretion of the Board of Directors, will be dependent upon future earnings, financial requirements and other factors.

Credit Ratings

The Company's credit ratings as of June 30, 2010, were:

	Moody's	S&P
Unenhanced 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. In connection with E.ON U.S.'s announcement that E.ON and E.ON US Investments Corp. had entered into a definitive agreement with PPL to sell to PPL all the equity interests of E.ON U.S., Moody's placed the debt ratings of the Company under review for possible downgrade. S&P affirmed the existing ratings of the Company. See Note 6 of Notes to Condensed 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.

LG&E has various derivative and non-derivative contracts, including contracts for the sale and purchase of electricity and fuel, natural gas and interest rate instruments, which contain provisions requiring LG&E to post additional collateral or permit the counterparty to terminate the contract if LG&E's credit rating were to fall below investment grade. At June 30, 2010, if LG&E's credit rating had been below investment grade, the Company would have been required to post an additional $5 million of collateral to counterparties for both derivative and non-derivative commodity and commodity-related contracts used in its generation, marketing and trading operations and interest rate contracts.

Future Capital Requirements

LG&E'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. LG&E expects its capital expenditures for the three-year period ending December 31, 2012, to total approximately $820 million, consisting primarily of the following:

($ in millions)	
Construction of distribution assets	$ 350
Construction of generation assets	340
Redevelopment of Ohio Falls hydroelectric facility	60
Information technology projects	35
Other projects	30
Construction of TC2	5
	$ 820

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. Credit market conditions can affect aspects of the availability, terms or methods in which the Company funds its capital requirements. LG&E anticipates funding future capital requirements through operating cash flow, debt and/or infusions of capital from its parent.

Controls and Procedures

Management 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 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 condensed 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.

LG&E 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, management has assessed the effectiveness of the Company's internal control over financial reporting as of December 31, 2009, using the criteria set forth by the Committee of Sponsoring Organizations of the Treadway Commission in *Internal Control – Integrated Framework*. Management has concluded that, as of December 31, 2009, the Company's internal control over financial reporting was effective based on those criteria. There have been no changes in the Company's internal control over financial reporting that occurred during the six months ended June 30, 2010, that has materially affected or is reasonably likely to materially affect the Company's internal control over financial reporting.

The effectiveness of the Company's internal control over financial reporting as of December 31, 2009, was audited by PricewaterhouseCoopers LLP, an independent accounting firm, as stated in its report which is included in the 2009 LG&E Annual Report.

Legal Proceedings

For a description of the significant legal proceedings, including, but not limited to, certain rates and regulatory, environmental, climate change and litigation matters, involving LG&E, reference is made to the information under the following captions of the Company's Annual Report for the year ended December 31, 2009: 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, 7, and 10 of this quarterly report. Except as described in this quarterly report, to date, the proceedings reported in the Company's Annual Report for the year ended December 31, 2009 have not materially changed.

Other

In the normal course of business, other lawsuits, claims, environmental actions and other governmental proceedings arise against LG&E. To the extent that damages are assessed in any of these lawsuits, the Company 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 the Company's financial position or results of operations.

LOUISVILLE GAS & ELECTIRC COMPANY
FINANCIAL STATEMENTS

SEPTEMBER 30, 2010

Louisville Gas and Electric Company

Condensed Financial Statements and Additional Information
(Unaudited)

As of September 30, 2010 and December 31, 2009
and for the three and nine months ended
September 30, 2010 and 2009

INDEX OF ABBREVIATIONS

AG	Attorney General of Kentucky
ARO	Asset Retirement Obligation
ASC	Accounting Standards Codification
BART	Best Available Retrofit Technology
CAIR	Clean Air Interstate Rule
CAMR	Clean Air Mercury Rule
CATR	Clean Air Transport Rule
CCN	Certificate of Public Convenience and Necessity
Clean Air Act	The Clean Air Act, as amended in 1990
CMRG	Carbon Management Research Group
Companies	LG&E and KU
Company	LG&E
DSM	Demand Side Management
ECR	Environmental Cost Recovery
EKPC	East Kentucky Power Cooperative, Inc.
E.ON	E.ON AG
E.ON U.S.	E.ON U.S. LLC
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)
GHG	Greenhouse Gas
GSC	Gas Supply Clause
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
LG&E	Louisville Gas and Electric Company
MISO	Midwest Independent Transmission System Operator, Inc.
MMBtu	Million British thermal units
Moody's	Moody's Investors Service, Inc.
Mw	Megawatts
Mwh	Megawatt hours
NAAQS	National Ambient Air Quality Standards
NOx	Nitrogen Oxide
OCI	Other Comprehensive Income
OVEC	Ohio Valley Electric Corporation
PBR	Performance Based Rates
PPL	PPL Corporation
S&P	Standard & Poor's Ratings Services
SCR	Selective Catalytic Reduction
SERC	SERC Reliability Corporation
Servco	LG&E and KU Services Company (formerly E.ON U.S. Services Inc.)
SIP	State Implementation Plan
SO_2	Sulfur Dioxide
TC2	Trimble County Unit 2
Virginia Commission	Virginia State Corporation Commission
WNA	Weather Normalization Adjustment

Louisville Gas and Electric Company
Condensed Financial Statements and Additional Information
(Unaudited)
As of September 30, 2010 and December 31, 2009
and for the three and nine months ended
September 30, 2010 and 2009

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PRICEWATERHOUSECOOPERS

PricewaterhouseCoopers LLP
500 West Main Street
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Report of Independent Accountants

To Shareholder of Louisville Gas and Electric Company:

We have reviewed the accompanying condensed balance sheet of Louisville Gas and Electric Company as of September 30, 2010, and the related condensed statements of income and comprehensive income, and of retained earnings for the three-month and nine-month periods ended September 30, 2010 and 2009 and the condensed statement of cash flows for the nine-month periods ended September 30, 2010 and 2009. This condensed interim financial information is the responsibility of the Company's management.

We conducted our review in accordance with standards established by the American Institute of Certified Public Accountants. A review of interim financial information consists principally of applying analytical procedures and making inquiries of persons responsible for financial and accounting matters. It is substantially less in scope than an audit conducted in accordance with auditing standards generally accepted in the United States of America, the objective of which is the expression of an opinion regarding the financial information taken as a whole. Accordingly, we do not express such an opinion.

Based on our review, we are not aware of any material modifications that should be made to the accompanying condensed interim financial information for it to be in conformity with accounting principles generally accepted in the United States of America.

We have previously audited, in accordance with auditing standards generally accepted in the United States of America, the balance sheet of Louisville Gas and Electric Company as of December 31, 2009, and the related statements of income and comprehensive income, retained earnings, and of cash flows for the year then ended (not presented herein), and in our report dated March 19, 2010, we expressed an unqualified opinion on those financial statements. In our opinion, the information set forth in the accompanying condensed balance sheet information as of December 31, 2009, is fairly stated in all material respects in relation to the balance sheet from which it has been derived.

PricewaterhouseCoopers LLP

October 29, 2010

Louisville Gas and Electric Company
Condensed Statements of Income
(Unaudited)
(Millions of $)

	Three Months Ended September 30, 2010	Three Months Ended September 30, 2009	Nine Months Ended September 30, 2010	Nine Months Ended September 30, 2009
Operating revenues:				
Electric (Note 11)	$ 297	$ 248	$ 776	$ 711
Gas	30	28	196	270
Total operating revenues	327	276	972	981
Operating expenses:				
Fuel for electric generation	104	83	277	257
Power purchased (Note 11)	12	10	41	43
Gas supply expenses	10	10	103	189
Other operation and maintenance expenses	89	44	263	251
Depreciation, accretion and amortization	35	35	104	102
Total operating expenses	250	182	788	842
Operating income	77	94	184	139
Derivative gain (loss) (Note 4)	29	(4)	18	12
Interest expense (Notes 4 and 8)	5	5	14	13
Interest expense to affiliated companies (Notes 8 and 11)	6	6	20	20
Other income (expense) – net	-	-	(1)	(1)
Income before income taxes	95	79	167	117
Income tax expense (Note 7)	35	29	60	41
Net income	$ 60	$ 50	$ 107	$ 76

The accompanying notes are an integral part of these condensed financial statements.

Louisville Gas and Electric Company

Condensed Statements of Comprehensive Income

(Unaudited)

(Millions of $)

	Three Months Ended September 30, 2010	Three Months Ended September 30, 2009	Nine Months Ended September 30, 2010	Nine Months Ended September 30, 2009
Net income	$ 60	$ 50	$ 107	$ 76
Gain (loss) on derivative instruments and hedging activities – net of tax (expense) benefit of $(8), $1, $(7) and $(1), respectively (Note 4)	13	(2)	10	2
Comprehensive income	$ 73	$ 48	$ 117	$ 78

Condensed Statements of Retained Earnings

(Unaudited)

(Millions of $)

	Three Months Ended September 30, 2010	Three Months Ended September 30, 2009	Nine Months Ended September 30, 2010	Nine Months Ended September 30, 2009
Balance at beginning of period	$ 772	$ 686	$ 755	$ 740
Net income	60	50	107	76
	832	736	862	816
Cash dividends declared (Note 11)	(25)	-	(55)	(80)
Balance at end of period	$ 807	$ 736	$ 807	$ 736

The accompanying notes are an integral part of these condensed financial statements.

Louisville Gas and Electric Company
Condensed Balance Sheets
(Unaudited)
(Millions of $)

	September 30, 2010	December 31, 2009
Assets		
Current assets:		
Cash and cash equivalents	$ 4	$ 5
Accounts receivable – net:		
Customer – less reserves of $2 in 2010 and $1 in 2009	121	131
Affiliated companies	17	53
Other — less reserves of $1 in 2010 and $1 in 2009	10	12
Materials and supplies:		
Fuel (predominantly coal)	66	61
Gas stored underground	61	56
Other materials and supplies	34	33
Regulatory assets (Note 2)	21	14
Prepayments and other current assets	14	18
Total current assets	348	383
Property, plant and equipment:		
Regulated utility plant – electric and gas	4,333	4,200
Accumulated depreciation	(1,757)	(1,708)
Net regulated utility plant	2,576	2,492
Construction work in progress	312	342
Property, plant and equipment – net	2,888	2,834
Deferred debits and other assets:		
Collateral deposit (Notes 4 and 5)	21	17
Regulatory assets (Note 2):		
Pension and postretirement benefits	204	204
Other regulatory assets	175	125
Other assets	5	5
Total deferred debits and other assets	405	351
Total assets	$ 3,641	$ 3,568

The accompanying notes are an integral part of these condensed financial statements.

Louisville Gas and Electric Company
Condensed Balance Sheets (continued)
(Unaudited)
(Millions of $)

	September 30, 2010	December 31, 2009
Liabilities and Equity		
Current liabilities:		
Current portion of long-term debt (Notes 5 and 8)	$ 120	$ 120
Notes payable to affiliated company (Notes 8 and 11)	122	170
Accounts payable	82	97
Accounts payable to affiliated companies (Note 11)	39	28
Customer deposits	25	22
Regulatory liabilities (Note 2)	13	38
Other current liabilities	52	58
Total current liabilities	453	533
Long-term debt:		
Long-term debt (Notes 5 and 8)	291	291
Long-term debt to affiliated company (Notes 5, 8 and 11)	485	485
Total long-term debt	776	776
Deferred credits and other liabilities:		
Deferred income taxes	416	373
Accumulated provision for pensions and related benefits (Note 6)	193	198
Investment tax credits (Note 7)	46	48
Asset retirement obligations (Note 3)	62	31
Regulatory liabilities (Note 2):		
Accumulated cost of removal of utility plant	270	256
Other regulatory liabilities	39	47
Derivative liabilities (Notes 4 and 5)	50	28
Other liabilities	21	25
Total deferred credits and other liabilities	1,097	1,006
Common equity:		
Common stock, without par value –		
Authorized 75,000,000 shares, outstanding 21,294,223 shares	424	424
Additional paid-in capital	84	84
Accumulated other comprehensive loss	-	(10)
Retained earnings	807	755
Total common equity	1,315	1,253
Total liabilities and equity	$ 3,641	$ 3,568

The accompanying notes are an integral part of these condensed financial statements.

Louisville Gas and Electric Company
Condensed Statements of Cash Flows
(Unaudited)
(Millions of $)

	For the Nine Months Ended September 30, 2010	2009
Cash flows from operating activities:		
Net income	$ 107	$ 76
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation, accretion and amortization	104	102
Deferred income taxes – net	32	29
Investment tax credits (Note 7)	(2)	-
Provision for pension and postretirement benefits	17	21
Unrealized (gain) loss on derivatives (Note 4)	14	(24)
Regulatory asset for unrealized gain on interest rate swaps (Note 2)	(22)	-
Other	1	1
Changes in current assets and liabilities:		
Accounts receivable	2	86
Materials and supplies	(11)	45
Regulatory assets and liabilities	(32)	42
Accounts payable	(16)	(44)
Accounts payable to affiliated companies	11	(11)
Other current assets and liabilities	1	3
Pension and postretirement funding (Note 6)	(24)	(13)
Other regulatory assets and liabilities	(12)	(45)
Other – net	(8)	8
Net cash provided by operating activities	162	276
Cash flows from investing activities:		
Construction expenditures	(108)	(127)
Proceeds from sale of assets to affiliate	48	-
Change in non-hedging derivatives (Note 4)	-	6
Net cash used in investing activities	(60)	(121)
Cash flows from financing activities:		
Borrowings from affiliated company (Note 8)	21	-
Repayments on borrowings from affiliated company (Note 8)	(69)	(73)
Payment of dividends (Note 11)	(55)	(80)
Net cash used in financing activities	(103)	(153)
Change in cash and cash equivalents	(1)	2
Cash and cash equivalents at beginning of period	5	4
Cash and cash equivalents at end of period	$ 4	$ 6

The accompanying notes are an integral part of these condensed financial statements.

Louisville Gas and Electric Company
Notes to Condensed Financial Statements
(Unaudited)

Note 1 – General

LG&E'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 condensed financial statements include all adjustments, consisting only of normal recurring adjustments, necessary for fair statements of income, comprehensive income, and retained earnings, balance sheets, and statements of 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 condensed financial statements and notes should be read in conjunction with the Company's Financial Statements and Additional Information ("Annual Report") for the year ended December 31, 2009, including the audited financial statements and notes therein.

The December 31, 2009, condensed balance sheet included herein is derived from the December 31, 2009, audited balance sheet. Amounts reported in the condensed statements of income are not necessarily indicative of amounts expected for the respective annual periods due to the effects of seasonal temperature variations on energy consumption, regulatory rulings, the timing of maintenance on electric generating units, changes in mark-to-market valuations, changing commodity prices and other factors.

Certain reclassification entries have been made to the previous year's financial statements to conform to the 2010 presentation with no impact on capitalization or previously reported net income. However, total assets and liabilities both increased by $1 million, cash flows provided by operating activities decreased by $6 million and cash flows used in investing activities decreased by $6 million.

PPL Acquisition

On April 28, 2010, E.ON U.S. announced that a Purchase and Sale Agreement (the "Agreement") had been entered into among E.ON US Investments, PPL and E.ON.

The Agreement provides for the sale of E.ON U.S. to PPL. Pursuant to the Agreement, at closing, PPL will acquire all of the outstanding limited liability company interests of E.ON U.S. for cash consideration of $2.6 billion. In addition, pursuant to the Agreement, PPL agreed to assume $764 million of pollution control bonds and medium term notes and to repay indebtedness owed by E.ON U.S. and its subsidiaries to E.ON US Investments and its affiliates. Such affiliate indebtedness is currently estimated to be $4.2 billion. The aggregate consideration payable by PPL on closing is currently estimated to be $7.6 billion (including the assumed indebtedness), subject to contractually agreed adjustments.

The transaction is subject to customary closing conditions, including the expiration or termination of the applicable waiting period under the Hart-Scott-Rodino Act, receipt of required regulatory approvals (including state regulators in Kentucky, Virginia and Tennessee, and the FERC) and the absence of injunctions or restraints imposed by governmental entities. As of October 26, 2010, all of the required regulatory approvals were received, and the transaction is expected to close on November 1, 2010.

Change of control and financing-related applications were filed on May 28, 2010, with the Kentucky Commission and on June 15, 2010, with the Virginia Commission and the Tennessee Regulatory Authority. An application with the FERC was filed on June 28, 2010. During the second quarter of 2010, a number of parties were granted intervenor status in the Kentucky Commission proceedings, and data request filings and responses occurred. Early termination of the Hart-Scott-Rodino waiting period was received on August 2, 2010.

A hearing in the Kentucky Commission proceedings was held on September 8, 2010, at which time a unanimous settlement agreement was presented. In the settlement, LG&E and KU commit that no base rate increases would take effect before January 1, 2013. The LG&E and KU rate increases that took effect on August 1, 2010, were not impacted by the settlement. Under the terms of the settlement, the Companies retain the right to seek approval for the deferral of "extraordinary and uncontrollable costs." Interim rate adjustments will continue to be permissible during that period for existing fuel, environmental and demand-side management cost trackers. The agreement also substitutes an acquisition savings shared deferral mechanism for the requirement that the Companies file a synergies plan with the Kentucky Commission. This mechanism, which will be in place until the earlier of five years or the first day of the year in which a base rate increase becomes effective, permits the Companies to earn up to a 10.75 percent return on equity. Any earnings above a 10.75 percent return on equity will be shared with customers on a 50%/50% basis. On September 30, 2010, the Kentucky Commission issued an Order approving the transfer of ownership of LG&E and KU via the acquisition of E.ON U.S. by PPL, incorporating the terms of the submitted settlement. On October 19, 2010 and October 21, 2010, respectively, Orders approving the acquisition of E.ON U.S. by PPL were received from the Virginia Commission and the Tennessee Regulatory Authority. The Commissions' Orders contained a number of other commitments with regard to operations, workforce, community involvement and other matters.

In mid-September 2010, LG&E and KU and other applicants in the FERC change of control proceeding reached an agreement with the protesters, whereby such protests have been withdrawn. The agreement, which has subsequently been filed for consideration with the FERC, includes various conditional commitments, such as a continuation of certain existing undertakings with protesters in prior cases, an agreement not to terminate certain KU municipal customer contracts prior to January 2017, an exclusion of any transaction-related costs from wholesale energy and tariff customer rates to the extent that the Company has agreed to not seek the same transaction-related cost from retail customers and agreements to coordinate with protesters in certain open or ongoing matters. A FERC Order approving the transaction was received on October 26, 2010.

On September 30, 2010, LG&E received Kentucky Commission approval to complete certain refinancing transactions in connection with the anticipated PPL acquisition and other business factors. Based on credit and financial market conditions, LG&E anticipates issuing up to $535 million in first mortgage bonds, the proceeds of which will substantially be used to refund existing long-term intercompany debt. On October 22, 2010, as required by existing covenants, in connection with the anticipated issuance of any such secured debt, LG&E completed collateralization of certain outstanding pollution control bond debt series which were formerly unsecured. Pursuant to such collateralization, approximately $574 million in existing pollution control debt (including $163 million of reacquired bonds) became collateralized debt, supported by a first mortgage lien. LG&E also anticipates replacing its $125 million bilateral lines of credit with unaffiliated institutions by entering into a multi-year revolving credit facility with several financial institutions in an aggregate amount not to exceed $400 million. LG&E may complete these transactions, in whole or in part, during late 2010 and early 2011. See Note 8, Short-Term and Long-Term Debt, for further information regarding the refinancing, remarketing or conversion of existing pollution control debt.

Recent Accounting Pronouncements

Fair Value Measurements

In January 2010, the FASB issued guidance related to fair value measurement disclosures requiring separate disclosure of amounts of significant transfers in and out of level 1 and level 2 fair value measurements and separate information about purchases, sales, issuances and settlements within level 3 measurements. This guidance is effective for the interim and annual reporting periods beginning after December 15, 2009, except for the disclosures about the roll-forward of activity in level 3 fair value measurements. Those disclosures are effective for fiscal years beginning after December 15, 2010, and for interim periods within those fiscal years. This guidance has no impact on the Company's results of operations, financial position, liquidity or disclosures.

Note 2 – Rates and Regulatory Matters

LG&E's base rates are calculated based on a return on capitalization (common equity, long-term debt and notes payable) including certain regulatory adjustments to exclude non-regulated investments and environmental compliance plans recovered separately through the ECR mechanism. Currently, none of the regulatory assets or regulatory liabilities are excluded from the return on capitalization utilized in the calculation of base rates; therefore, a return is earned on all regulatory assets.

For a description of each line item of regulatory assets and liabilities and for descriptions of certain matters which may not have undergone material changes relating to the period covered by this quarterly report, reference is made to Note 2, Rates and Regulatory Matters, of LG&E's Annual Report for the year ended December 31, 2009.

2010 Electric and Gas Rate Cases

In January 2010, LG&E filed an application with the Kentucky Commission requesting an increase in electric base rates of approximately 12%, or $95 million annually, and its gas base rates of approximately 8%, or $23 million annually, including an 11.5% return on equity for electric and gas. LG&E requested the increase, based on the twelve month test year ended October 31, 2009, to become effective on and after March 1, 2010. The requested rates were suspended until August 1, 2010. A number of intervenors entered the rate case, including the AG, certain representatives of industrial and low-income groups and other third parties, and submitted filings challenging the Company's requested rate increases, in whole or in part. A hearing was held on June 8, 2010. LG&E and all of the intervenors, except for the AG, agreed to a stipulation providing for an increase in electric base rates of $74 million annually and gas base rates of $17 million annually and filed a request with the Kentucky Commission to approve such settlement. An Order in the proceeding was issued in July 2010, approving all the provisions in the stipulation. The new rates became effective on August 1, 2010.

Regulatory Assets and Liabilities

The following regulatory assets and liabilities were included in LG&E's balance sheets as of:

(in millions)	September 30, 2010	December 31, 2009
Current regulatory assets:		
Storm restoration (a)	$ 7	$ -
GSC (b)	4	3
FAC (c)	4	-
ECR (c)	3	7
MISO exit (a)	1	1
Other (d)	2	3
Total current regulatory assets	$ 21	$ 14
Non-current regulatory assets:		
Pension and postretirement benefits (e)	$ 204	$ 204
Other non-current regulatory assets:		
Storm restoration (a)	59	67
Mark-to-market impact of interest rate swaps (f)	50	-
ARO (g)	33	30
Unamortized loss on bonds (a)	21	22
Swap termination (a)	9	-
MISO exit (a)	1	4
Other (d)	2	2
Subtotal other non-current regulatory assets	175	125
Total non-current regulatory assets	$ 379	$ 329
Current regulatory liabilities:		
GSC	$ 8	$ 34
DSM	5	4
Total current regulatory liabilities	$ 13	$ 38
Non-current regulatory liabilities:		
Accumulated cost of removal of utility plant	$ 270	$ 256
Other non-current regulatory liabilities:		
Deferred income taxes – net	36	41
MISO exit	-	3
Other (h)	3	3
Subtotal other non-current regulatory liabilities	39	47
Total non-current regulatory liabilities	$ 309	$ 303

(a) These regulatory assets are recovered through base rates.
(b) The GSC and gas performance-based ratemaking regulatory assets have separate recovery mechanisms with recovery within eighteen months.

(c) The FAC and ECR regulatory assets have separate recovery mechanisms with recovery within twelve months.

(d) Other regulatory assets:

- A return was earned on the balance of Mill Creek Ash Pond costs included in other current regulatory assets at December 31, 2009, as well as recovery of these costs. There is no remaining balance as of September 30, 2010.
- Other current and non-current regulatory assets, including the CMRG and KCCS contributions, an EKPC FERC transmission settlement agreement and rate case expenses, are recovered through base rates.
- The current portion of the swap termination and unamortized loss on bonds is recovered through base rates.

(e) LG&E generally recovers this asset through pension expense included in the calculation of base rates.

(f) Beginning in the third quarter of 2010, based on an Order from the Kentucky Commission in the 2010 rate case whereby the cost of a terminated rate swap was allowed to be recovered in base rates, the mark-to-market impact of the effective and ineffective interest rate swaps is considered probable of recovery through rates and therefore included in regulatory assets. No return is currently earned on this regulatory asset. See Note 4, Derivative Financial Instruments, for further discussion.

(g) When an asset with an ARO is retired, the related ARO regulatory asset will be offset against the associated ARO regulatory liability, ARO asset and ARO liability.

(h) Includes ARO liabilities, which are established from the removal costs accrued through depreciation under regulatory accounting for assets associated with AROs.

Storm Restoration

In January 2009, a significant ice storm passed through LG&E's service territory causing approximately 205,000 customer outages and was followed closely by a severe wind storm in February 2009, which caused approximately 37,000 customer outages. LG&E incurred $44 million in incremental operation and maintenance expenses and $10 million in capital expenditures related to the restoration following the two storms. The Company filed an application with the Kentucky Commission in April 2009, requesting approval to establish a regulatory asset and defer for future recovery approximately $45 million in incremental operation and maintenance expenses related to the storm restoration. In September 2009, the Kentucky Commission issued an Order allowing the Company to establish a regulatory asset of up to $45 million based on its actual costs for storm damages and service restoration due to the January and February 2009 storms. In September 2009, the Company established a regulatory asset of $44 million for actual costs incurred. The Company received approval in its 2010 base rate cases to recover this asset over a ten year period beginning August 1, 2010.

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, LG&E filed an application with the Kentucky Commission requesting approval to establish a regulatory asset and defer for future recovery approximately $24 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 $24 million based on its actual costs for storm damages and service restoration due to Hurricane Ike. In December 2008, the Company established a regulatory asset of $24 million for actual costs incurred.

The Company received approval in its 2010 electric base rate case to recover this asset over a ten year period beginning August 1, 2010.

GSC

In December 2009, LG&E filed with the Kentucky Commission an application to extend and modify its existing gas cost PBR. The current PBR was set to expire at the end of October 2010. In April 2010, the Kentucky Commission issued an Order approving a five year extension and the requested minor modifications to the PBR effective November 2010.

FAC

In August 2010, the Kentucky Commission initiated a six-month review of LG&E's FAC mechanism for the expense period ended April 2010. An order is expected by the end of the year.

In January 2010, the Kentucky Commission initiated a six-month review of LG&E's FAC mechanism for the expense period ended August 2009. In May 2010, an Order was issued approving the charges and credits billed through the FAC during the review period.

ECR

In July 2010, the Kentucky Commission initiated a six-month review of LG&E's environmental surcharge for the billing period ending April 2010. An order is expected in the fourth quarter of 2010.

In January 2010, the Kentucky Commission initiated a six-month review of LG&E's environmental surcharge for the billing period ending October 2009. In May 2010, an Order was issued approving the amounts billed through the ECR during the six-month period and the rate of return on capital and allowing recovery of the under-recovery position in subsequent monthly filings.

In June 2009, the Company filed an application for a new ECR plan with the Kentucky Commission seeking approval to recover investments in environmental upgrades and operations and maintenance costs at the Company's generating facilities. During 2009, LG&E reached a unanimous settlement with all parties to the case, and the Kentucky Commission issued an Order approving LG&E's application. Recovery on customer bills through the monthly ECR surcharge for these projects began with the February 2010 billing cycle.

MISO

In August 2010, the FERC issued three Orders accepting most facets of several MISO Revenue Sufficiency Guarantee ("RSG") compliance filings. The FERC ordered the MISO to issue refunds for RSG charges that were imposed by the MISO on the assumption that there were rate mismatches for the period beginning November 5, 2007 through the present. There is no financial statement impact to the Company from this Order, as the MISO had anticipated that the FERC would require these refunds and had preemptively included them in the resettlements paid in 2009. The FERC denied MISO's proposal to exempt certain resources from RSG charges, effective prospectively. The FERC accepted portions and rejected portions of the MISO's proposed RSG rate Redesign Proposal, which will be effective when the software is ready for implementation subject to further compliance filings. The impact of the Redesign Proposal on the Company cannot be estimated at this time.

Interest Rate Swaps

Interest rate swaps are accounted for on a fair value basis in accordance with the derivatives and hedging topic of the FASB ASC. Beginning in the third quarter of 2010, the unrealized gains and losses of the effective and ineffective interest rate swaps are included in a regulatory asset based on an Order from the Kentucky Commission in the 2010 rate case whereby the cost of a terminated swap was allowed to be recovered in base rates. Previously, interest rate swaps designated as effective cash flow hedges had resulting gains and losses recorded within OCI and common equity. The ineffective portion of interest rate swaps designated as cash flow hedges was previously recorded to earnings monthly, as was the entire change in the market value of the ineffective swaps. LG&E is able to recover the unrealized gains and losses on the interest rate swaps under its existing rate recovery structure as the interest expense on the swaps is realized.

Other Regulatory Matters

TC2 Depreciation

In August 2009, the Companies jointly filed an application with the Kentucky Commission to approve new common depreciation rates for applicable jointly-owned TC2-related generating, pollution control and other plant equipment and assets. During December 2009, the Kentucky Commission extended the data discovery process through January 2010, and authorized the Companies on an interim basis to begin using the depreciation rates for TC2 as proposed in the application. In March 2010, the Kentucky Commission issued a final Order approving the use of the proposed depreciation rates on a permanent basis.

TC2 Transmission Matters

LG&E's and KU's CCN for a transmission line associated with the TC2 construction has been challenged by certain property owners in Hardin County, Kentucky. In August 2006, the Companies obtained a successful dismissal of the challenge at the Franklin County Circuit Court, which was reversed by the Kentucky Court of Appeals in December 2007. In April 2009, the Kentucky Supreme Court granted LG&E's and KU's motion for discretionary review of the Court of Appeals' decision. In August 2010, the Kentucky Supreme Court issued an Order reversing the decision of the Kentucky Court of Appeals and reinstating the Franklin County Circuit Court's dismissal of the property owners' challenge to LG&E's and KU's CCN.

During 2008, LG&E's affiliate, KU, obtained various successful rulings at the Hardin County Circuit Court confirming its condemnation rights. In August 2008, several landowners appealed such rulings to the Kentucky Court of Appeals. In May 2010, the Kentucky Court of Appeals issued an Order affirming the Hardin Circuit Court's finding that KU had the right to condemn easements on the properties. In May 2010, the landowners filed a petition for reconsideration with the Court of Appeals. In July 2010, the Court of Appeals denied that petition. In August 2010, the landowners filed for discretionary review of that denial by the Kentucky Supreme Court.

In a separate proceeding, certain Hardin County landowners filed an action in federal district court in Louisville, Kentucky against the U.S. Army challenging the same transmission line claiming that certain Fort Knox-related sections of the line failed to comply with certain National Historic Preservation Act procedural requirements. In October 2009, the federal court granted the defendants' motion for summary judgment and dismissed the plaintiffs' claims. During November 2009, the petitioners filed submissions for review of the decision with the 6th Circuit Court of Appeals. In May 2010, the appellate court issued an order approving the plaintiffs' voluntary withdrawal of their appeals.

Consistent with the regulatory authorizations and relevant legal proceedings, the Companies have completed construction activities on temporary or permanent transmission line segments. During the second quarter of 2010, the Companies placed into operation an appropriate combination of permanent and temporary sections of the transmission line. While the Companies are not currently able to predict the ultimate outcome and possible financial effects of the remaining legal proceedings, the Companies do not believe the matter involves relevant or continuing risks to operations.

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 Regional Reliability Organizations ("RROs") by the North American Electric Reliability Corporation ("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 on the circumstances of the violation. The Companies are members of SERC, which acts as LG&E's and KU's RRO. During December 2009, SERC and the Companies agreed to settlements involving penalties totaling less than $1 million for each utility related to their self-reports during June and October 2008, concerning possible violations of standards. During December 2009 and April, July and August 2010, the Companies submitted ten self-reports relating to various standards, which self-reports remain in the early stages of RRO review, and therefore, the Companies are unable to estimate the outcome of these matters. Mandatory reliability standard settlements commonly also include non-penalty elements, including compliance steps and mitigation plans. Settlements with SERC proceed to NERC and FERC review before becoming final. While the Companies believe they are in compliance with the mandatory reliability standards, events of potential non-compliance may be identified from time-to-time. The Companies cannot predict such potential violations or the outcome of the self-reports described above.

Gas Customer Choice Study

In April 2010, the Kentucky Commission commenced a proceeding to investigate natural gas retail competition programs; their regulatory, financial and operational aspects and potential benefits, if any, of such programs to Kentucky consumers. A number of entities, including LG&E, are parties to the proceeding. Data discovery, inclusive of a public hearing to be held by the Kentucky Commission, continued through October 2010. An order in this proceeding is anticipated by year end.

Note 3 – Asset Retirement Obligation

A summary of LG&E's net ARO assets, ARO liabilities and regulatory assets established under the asset retirement and environmental obligations guidance of the FASB ASC, follows:

(in millions)	ARO Net Assets	ARO Liabilities	Regulatory Assets
As of December 31, 2009	$ 3	$ (31)	$ 30
ARO accretion	-	(2)	2
ARO revaluation	29	(30)	1
Removal cost incurred	-	1	-
As of September 30, 2010	$ 32	$ (62)	$ 33

As of September 30, 2010, the Company performed a revaluation of its AROs as a result of recently proposed environmental legislation and improved ability to forecast asset retirement costs due to recent construction and retirement activity.

Pursuant to regulatory treatment prescribed under the regulated operations guidance of the FASB ASC, an offsetting regulatory credit was recorded in depreciation and amortization in the income statement of $2 million for the nine months ended September 30, 2010, for the ARO accretion and depreciation expense. LG&E's AROs are primarily related to the final retirement of assets associated with generating units and natural gas wells.

LG&E transmission and distribution lines largely operate under perpetual property easement agreements which do not generally require restoration on removal of the property. Therefore, under the asset retirement and environmental obligations guidance of the FASB ASC, no material asset retirement obligations are recorded for transmission and distribution assets.

Note 4 – Derivative Financial Instruments

LG&E is subject to interest rate and commodity price risk related to on-going business operations. It currently manages these risks using derivative instruments, including swaps and forward contracts. The Company's policies allow for the interest rate risk to be managed through the use of fixed rate debt, floating rate debt and interest rate swaps. At September 30, 2010, a 100 basis point change in the benchmark rate on LG&E's variable rate debt, not effectively hedged by an interest rate swap, would impact pre-tax interest expense by $2 million annually.

The Company does not net collateral against derivative instruments.

Interest Rate Swaps

LG&E uses over-the-counter interest rate swaps to limit exposure to market fluctuations in interest expense. Pursuant to Company policy, use of these derivative instruments is intended to mitigate risk, earnings and cash flow volatility and is not speculative in nature.

LG&E's interest rate swap agreements range in maturity through 2033, with aggregate notional amounts of $179 million as of September 30, 2010 and December 31, 2009. Under these swap agreements, LG&E paid fixed rates averaging 4.52% and received variable rates based on LIBOR or the Securities Industry and Financial Markets Association's municipal swap index averaging 0.22% and 0.20% at September 30, 2010 and December 31, 2009, respectively. One swap hedging a portion of the Company's $83 million Trimble County 2000 Series A bond has been designated as a cash flow hedge and continues to be highly effective. The three remaining interest rate swaps are ineffective. The unrealized gains and losses on the effective and ineffective interest rate swaps are included in a regulatory asset based on an Order from the Kentucky Commission in the 2010 rate case, whereby the cost of a terminated swap was allowed to be recovered in base rates.

The fair value of the interest rate swaps is determined by a quote from the counterparty. This value is verified monthly by the Company using a model that calculates the present value of future payments under the swap utilizing current swap market rates obtained from another dealer active in the swap market and validated by market transactions. Market liquidity is considered, however, the valuation does not require an adjustment for market liquidity as the market is very active for the type of swaps used by the Company. LG&E considered the impact of its own credit risk and that of counterparties by evaluating credit ratings and financial information. LG&E and all counterparties had strong investment grade ratings at September 30, 2010. LG&E did not have any credit exposure to the swap counterparties, as it was in a liability position at September 30, 2010; therefore, the market valuation required no adjustment for counterparty credit risk. In addition, the Company and certain counterparties have agreed to post margin if the credit exposure exceeds certain thresholds. Cash collateral for interest rate swaps is classified as a long-term asset in the accompanying balance sheets.

The tables below show the fair value and balance sheet location of interest rate swap derivatives:

(in millions)

September 30, 2010

Derivative Designation	Balance Sheet Location	Fair Value
Hedging	Long-term derivative liability	$ 25
Non-hedging	Long-term derivative liability	25
		$ 50

December 31, 2009

Derivative Designation	Balance Sheet Location	Fair Value
Hedging	Long-term derivative liability	$ 19
Non-hedging	Long-term derivative liability	9
		$ 28

Beginning in the third quarter of 2010, the unrealized gains and losses of the effective and ineffective interest rate swaps are included in a regulatory asset, which offsets the hedging and non-hedging long-term derivative liabilities.

The interest rate swaps are accounted for on a fair value basis in accordance with the derivatives and hedging topic of the FASB ASC. The tables below show the pre-tax amount and income statement location of derivative gains and losses for the change in the mark-to-market value of the ineffective interest rate swaps, realized losses and the change in the ineffective portion of the interest rate swaps deemed highly effective, including the impact of reclassifying these amounts to regulatory assets during the three months ended September 30, 2010:

(in millions)		Three Months Ended September 30,	
Gain (Loss) Recognized in Income	Location	2010	2009
Reclassification to regulatory assets of unrealized loss on interest rate swaps	Derivative gain (loss)	$ 21	$ -
Unrealized loss on ineffective swaps	Derivative gain (loss)	-	(3)
Reclassification to regulatory assets of unrealized loss on terminated swap	Derivative gain (loss)	9	-
Realized loss on ineffective swaps	Derivative gain (loss)	(1)	(1)
		$ 29	$ (4)

For the three months ended September 30, 2009, LG&E recorded a pre-tax gain of less than $1 million in interest expense to reflect the change in the ineffective portion of the interest rate swaps deemed highly effective. During the three months ended September 30, 2010, the Company recorded a pre-tax gain of $21 million and $9 million, respectively, to reflect the reclassification of the ineffective swaps and the terminated swap to a regulatory asset.

(in millions)		Nine Months Ended September 30,	
Gain (Loss) Recognized in Income	Location	2010	2009
Change in the ineffective portion deemed highly effective	Interest expense	$ -	$ 1
Reclassification to regulatory assets of unrealized loss on interest rate swaps	Derivative gain (loss)	21	-
Unrealized gain (loss) on ineffective swaps	Derivative gain (loss)	(10)	14
Reclassification to regulatory assets of unrealized loss on terminated swap	Derivative gain (loss)	9	-
Realized loss on ineffective swaps	Derivative gain (loss)	(2)	(2)
		$ 18	$ 13

During the nine months ended September 30, 2010, the Company recorded a pre-tax gain of $21 million and $9 million, respectively, to reflect the reclassification of the ineffective swaps and the terminated swap to a regulatory asset.

The gain on hedging interest rate swaps recognized in OCI for the three and nine months ended September 30, 2010, was $21 million and $17 million, respectively. For the three and nine months ended September 30, 2010, the gain on derivatives reclassified from accumulated OCI to regulatory assets was $23 million.

Prior to including the unrealized gains and losses on the effective and ineffective interest rate swaps in regulatory assets, amounts previously recorded in accumulated OCI were reclassified into earnings in the same period during which the hedged forecasted transaction affected earnings. The amount amortized from OCI to income in the three and nine months ended September 30, 2010 and 2009, was less than $1 million, respectively.

A decline of 100 basis points in the current market interest rates would reduce the fair value of LG&E's interest rate swaps by approximately $31 million.

Energy Trading and Risk Management Activities

LG&E 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 the derivatives and hedging topic of the FASB ASC.

Energy trading and risk management contracts are valued using prices based on active trades from Intercontinental Exchange Inc. In the absence of a traded price, midpoints of the best bids and offers are the primary determinants of valuation. When sufficient trading activity is unavailable, other inputs 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. 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 2010 or 2009. Changes in market pricing, interest rate and volatility assumptions were made during both years.

The tables below show the fair value and balance sheet location of energy trading and risk management derivative contracts:

(in millions)

September 30, 2010

	Asset Derivatives		Liability Derivatives	
Derivative Designation	Balance Sheet Location	Fair Value	Balance Sheet Location	Fair Value
Non-hedging	Prepayments and other current assets	$ 2	Other current liabilities	$ 1

December 31, 2009

	Asset Derivatives		Liability Derivatives	
Derivative Designation	Balance Sheet Location	Fair Value	Balance Sheet Location	Fair Value
Non-hedging	Prepayments and other current assets	$ 2	Other current liabilities	$ 2

The Company maintains credit policies intended to minimize credit risk in wholesale marketing and trading activities by assessing the creditworthiness of potential counterparties prior to entering into transactions with them and continuing to evaluate their creditworthiness once transactions have been initiated. To further mitigate credit risk, LG&E seeks to enter into netting agreements or require cash deposits, letters of credit and parental company guarantees as security from counterparties. The Company uses S&P, Moody's and definitive qualitative and quantitative data to assess the financial strength of counterparties on an on-going basis. If no external rating exists, LG&E assigns an internally generated rating for which it sets appropriate risk parameters. As risk management contracts are valued based on changes in market prices of the related commodities, credit exposures are revalued and monitored on a daily basis. At September 30, 2010, 100% of the trading and risk management commitments were with counterparties rated BBB-/Baa3 equivalent or better. The Company has reserves 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 September 30, 2010 and December 31, 2009, counterparty credit reserves related to energy trading and risk management contracts were less than $1 million.

The net volume of electricity-based financial derivatives outstanding at September 30, 2010 and December 31, 2009, was zero and 587,800 Mwhs, respectively. No cash collateral related to the energy trading and risk management contracts was required at September 30, 2010. Cash collateral related to the energy trading and risk management contracts was $2 million at December 31, 2009. Cash collateral related to the energy trading and risk management contracts is categorized as other accounts receivable in the accompanying balance sheet.

LG&E manages the price risk of its estimated future excess economic generation capacity using market-traded forward contracts. Hedge accounting treatment has not been elected for these transactions, and therefore realized and unrealized gains and losses are included in the statements of income.

The following tables present the effect of market-traded forward contract derivatives not designated as hedging instruments on income:

(in millions)		Three Months Ended September 30,	
Gain (Loss) Recognized in Income	Location	2010	2009
Realized gain	Electric revenues	$ 1	$ 5
Unrealized loss	Electric revenues	(1)	(3)
		$ -	$ 2

		Nine Months Ended September 30,	
Gain (Loss) Recognized in Income	Location	2010 (a)	2009
Realized gain	Electric revenues	$ 3	$ 8
Unrealized loss	Electric revenues	-	(1)
		$ 3	$ 7

(a) Unrealized gains were less than $1 million

Credit Risk Related Contingent Features

Certain of the Company's derivative instruments contain provisions that require the Company to provide immediate and on-going collateralization on derivative instruments in net liability positions based on the Company's credit ratings from each of the major credit rating agencies. At September 30, 2010, there are no energy trading and risk management contracts with credit risk related contingent features that are in a liability position and no collateral posted in the normal course of business. The aggregate mark-to-market value of all interest rate swaps with credit risk related contingent features that are in a liability position on September 30, 2010, is $34 million, for which the Company has posted collateral of $21 million in the normal course of business. If the credit risk related contingent features underlying these agreements were triggered on September 30, 2010, due to a one notch downgrade in the Company's credit rating, the Company would be required to post an additional $4 million of collateral to its counterparties for the interest rate swaps. At September 30, 2010, a one notch downgrade of the Company's credit rating would have no effect on the energy trading and risk management contracts or collateral required.

Note 5 – Fair Value Measurements

LG&E adopted the fair value guidance in the FASB ASC in two phases. Effective January 1, 2008, the Company adopted it for all financial instruments and non-financial instruments accounted for at fair value on a recurring basis, and January 1, 2009, the Company adopted it for all non-financial instruments accounted for at fair value on a non-recurring basis. The FASB ASC guidance clarifies that fair value is an exit price, representing the amount that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants. As such, fair value is a market-based measurement that should be determined based on assumptions that market participants would use in pricing an asset or a liability. As a basis for considering such assumptions, the FASB ASC guidance establishes a three-tier value hierarchy, which prioritizes the inputs used in the valuation methodologies in measuring fair value.

The carrying values and estimated fair values of LG&E's non-trading financial instruments follow:

(in millions)	September 30, 2010		December 31, 2009	
	Carrying Value	Fair Value	Carrying Value	Fair Value
Long-term bonds (including current portion of $120 million)	$ 411	$ 418	$ 411	$ 411
Long-term debt to affiliated company	485	549	485	512
Derivative liability – interest rate swaps	50	50	28	28

The long-term bond valuations reflect prices quoted by investment banks, which are active in the market for these instruments. The fair value of the long-term debt due to affiliated company is determined using an internal valuation model that discounts the future cash flows of each loan at current market rates as determined based on quotes from investment banks that are actively involved in capital markets for utilities and factor in LG&E's credit ratings and default risk. The fair values of the interest rate swaps reflect price quotes from investment banks, consistent with the fair value measurements and disclosures topic of the FASB ASC. This value is verified monthly by the Company using a model that calculates the present value of future payments under the swap utilizing current swap market rates obtained from another dealer active in the swap market and validated by market transactions. The fair values of cash and cash equivalents, accounts receivable, accounts payable and notes payable are substantially the same as their carrying values.

LG&E has classified the applicable financial assets and liabilities that are accounted for at fair value into the three levels of the fair value hierarchy, as defined by the fair value measurements and disclosures topic of the FASB ASC, as follows:

- Level 1 – Observable inputs that reflect quoted prices (unadjusted) for identical assets or liabilities in active markets
- Level 2 – Include other inputs that are directly or indirectly observable in the marketplace
- Level 3 – Unobservable inputs which are supported by little or no market activity

The fair value hierarchy also requires an entity to maximize the use of observable inputs and minimize the use of unobservable inputs when measuring fair value.

The Company classifies its derivative cash collateral balances within level 1 based on the funds being held in a demand deposit account. The Company classifies its derivative energy trading and risk management contracts and interest rate swaps within level 2 because it values them using prices actively quoted for proposed or executed transactions, quoted by brokers or observable inputs other than quoted prices.

The following tables set forth, by level within the fair value hierarchy, LG&E's financial assets and liabilities that were accounted for at fair value on a recurring basis.

(in millions) September 30, 2010	Level 1	Level 2	Total
Financial assets:			
Energy trading and risk management contracts	$ -	$ 2	$ 2
Interest rate swap cash collateral	21	-	21
Total financial assets	$ 21	$ 2	$ 23
Financial liabilities:			
Energy trading and risk management contracts	$ -	$ 1	$ 1
Interest rate swaps	-	50	50
Total financial liabilities	$ -	$ 51	$ 51

December 31, 2009	Level 1	Level 2	Total
Financial assets:			
Energy trading and risk management contract cash collateral	$ 2	$ -	$ 2
Energy trading and risk management contracts	-	2	2
Interest rate swap cash collateral	17	-	17
Total financial assets	$ 19	$ 2	$ 21
Financial liabilities:			
Energy trading and risk management contracts	$ -	$ 2	$ 2
Interest rate swaps	-	28	28
Total financial liabilities	$ -	$ 30	$ 30

No cash collateral related to the energy trading and risk management contracts was required at September 30, 2010.

There were no level 3 measurements for the periods ending September 30, 2010 and December 31, 2009.

Note 6 – Pension and Other Postretirement Benefit Plans

Net Periodic Benefit Costs

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 LG&E employees and Servco employees who are providing services to LG&E. The Servco costs are allocated to LG&E based on employees' labor charges and are approximately 43% and 44% of Servco costs for September 30, 2010 and 2009, respectively.

(in millions)

	Pension Benefits Three Months Ended September 30,					
	2010			2009		
	LG&E	Servco Allocation to LG&E	Total LG&E	LG&E	Servco Allocation to LG&E	Total LG&E
Service cost	$ 1	$ 2	$ 3	$ 1	$ 1	$ 2
Interest cost	7	2	9	7	2	9
Expected return on plan assets	(6)	(2)	(8)	(6)	(1)	(7)
Amortization of prior service cost	1	-	1	1	-	1
Amortization of actuarial loss	2	-	2	3	-	3
Net periodic benefit cost	$ 5	$ 2	$ 7	$ 6	$ 2	$ 8

	Other Postretirement Benefits Three Months Ended September 30,					
	2010			2009		
	LG&E	Servco Allocation to LG&E (a)	Total LG&E	LG&E	Servco Allocation to LG&E (a)	Total LG&E
Interest cost	$ 1	$ -	$ 1	$ 1	$ -	$ 1
Amortization of prior service cost	-	-	-	1	-	1
Net periodic benefit cost	$ 1	$ -	$ 1	$ 2	$ -	$ 2

(a) amounts are less than $1 million

Pension Benefits
Nine Months Ended September 30,

	2010			2009		
	LG&E	Servco Allocation to LG&E	Total LG&E	LG&E	Servco Allocation to LG&E	Total LG&E
Service cost	$ 3	$ 4	$ 7	$ 3	$ 3	$ 6
Interest cost	20	5	25	19	5	24
Expected return on plan assets	(19)	(4)	(23)	(16)	(4)	(20)
Amortization of prior service cost	4	-	4	4	1	5
Amortization of actuarial loss	7	1	8	9	2	11
Net periodic benefit cost	$ 15	$ 6	$ 21	$ 19	$ 7	$ 26

Other Postretirement Benefits
Nine Months Ended September 30,

	2010			2009		
	LG&E	Servco Allocation to LG&E (a)	Total LG&E	LG&E	Servco Allocation to LG&E (a)	Total LG&E
Service cost	$ 1	$ -	$ 1	$ 1	$ 1	$ 2
Interest cost	3	-	3	4	-	4
Amortization of prior service cost	1	-	1	1	-	1
Net periodic benefit cost	$ 5	$ -	$ 5	$ 6	$ 1	$ 7

(a) amounts are less than $1 million

Contributions

In January 2010, LG&E and Servco made discretionary pension plan contributions of $20 million and $9 million, respectively. The amount of future contributions to the pension plan will depend on the actual return on plan assets and other factors, but the Company's intent is to fund the pension plans in a manner consistent with the requirements of the Pension Protection Act of 2006.

Through September 2010, LG&E made contributions to other postretirement benefit plans totaling $4 million. An additional contribution totaling $2 million was made in October. The Company anticipates further funding to match the annual postretirement expense and funding the 401(h) plan up to the maximum amount allowed by law.

Health Care Reform

In March 2010, Health Care Reform (the Patient Protection and Affordable Care Act of 2010) was signed into law. Many provisions of Health Care Reform do not take effect for an extended period of time, and many aspects of the law which are currently unclear or undefined will likely be clarified in future regulations.

Specific provisions within Health Care Reform that may impact LG&E include:

- Beginning in 2011, requirements extend dependent coverage up to age 26, remove the $2 million lifetime maximum and eliminate cost sharing for certain preventative care procedures.
- Beginning in 2018, a potential excise tax is expected on high-cost plans providing health coverage that exceeds certain thresholds.

LG&E continues to evaluate all implications of Health Care Reform on its benefit programs but at this time cannot predict the significance of those implications.

Note 7 – 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 LG&E, 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. The Company also files income tax returns in various state jurisdictions. While 2007 and later years are open under the federal statute of limitations, Revenue Agent Reports for 2006-2008 have been received from the IRS, effectively closing these years to additional audit adjustments. Tax years beginning with 2007 were examined under an IRS pilot program, "Compliance Assurance Process" ("CAP"). This program accelerates the IRS' review to begin during the year applicable to the return and ends 90 days after the return is filed. Adjustments for 2007, agreed to and recorded in January 2009, were comprised of $5 million of depreciation-related differences. For 2008, the IRS allowed additional deductions in connection with the Company's application for a change in repair deductions and disallowed some of the bonus depreciation claimed on the original return. The net temporary tax impact for the Company was $13 million and was recorded in the second quarter of 2010. Tax years 2009 and 2010 are also being examined under CAP. The 2009 federal return was filed in the third quarter, and the IRS issued a Partial Acceptance Letter with the 2009 return. The IRS is continuing to review bonus depreciation, storms and other repairs, contributions in aid of construction and purchased gas adjustments. No material impact is expected from the IRS review. For the tax year 2010, no material items have been raised by the IRS at this time.

Additions and reductions of uncertain tax positions during 2010 and 2009 were less than $1 million. Possible amounts of uncertain tax positions for LG&E 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. If recognized, the less than $1 million of unrecognized tax benefits would reduce the effective income tax rate.

The amount LG&E recognized as interest expense and interest accrued related to unrecognized tax benefits was less than $1 million as of September 30, 2010 and December 31, 2009. The interest expense and interest accrued is based on IRS and Kentucky Department of Revenue large corporate interest rates for underpayment of taxes. At the date of adoption, the Company accrued less than $1 million in interest expense on uncertain tax positions. LG&E records the interest as interest expense and penalties as operating expenses in the income statement and accrued expenses in the balance sheet, on a pre-tax basis. No penalties were accrued by the Company through September 30, 2010.

In June 2006, the Companies 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 LG&E was selected to receive $24 million in tax credits. A final IRS certification required to obtain the investment tax credits was received in August 2007. In September 2007, LG&E received an Order from the Kentucky Commission approving the accounting of the investment tax credits, which includes a full depreciation basis adjustment for the amount of the credits. Based on eligible construction expenditures incurred, LG&E recorded investment tax credits of $1 million and $3 million during the three and nine months ended September 30, 2009, decreasing current federal income taxes. As of December 31, 2009, LG&E had recorded its maximum credit of $24 million. The income tax expense impact from amortizing these credits over the life of the related property will begin when the facility is placed in service, which is expected to occur by year end.

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. The plaintiffs voluntarily dismissed their complaint in August 2010.

A reconciliation of differences between the Company's income tax expense at the statutory U.S. federal income tax rate and the Company's actual income tax expense follows:

(in millions)	Three Months Ended September 30, 2010	Three Months Ended September 30, 2009	Nine Months Ended September 30, 2010	Nine Months Ended September 30, 2009
Statutory federal income tax expense	$ 33	$ 28	$ 58	$ 41
State income taxes – net of federal benefit	4	3	6	3
Other differences – net	(2)	(2)	(4)	(3)
Income tax expense	$ 35	$ 29	$ 60	$ 41
Effective income tax rate	36.8%	36.7%	35.9%	35.0%

The amounts shown in the table above are rounded to the nearest $1 million; however, the effective income tax rates are based on actual underlying amounts. Other differences – net includes the qualified production activities deduction, amortization of investment tax credits and excess deferred tax on depreciation.

State income taxes – net of federal benefit were lower in the nine months ended September 30, 2009, due to a coal credit recorded in 2009.

Note 8 – Short-Term and Long-Term Debt

LG&E's long-term debt includes $120 million of pollution control bonds that are classified as current portion of long-term debt because these bonds are subject to tender for purchase at the option of the holder and to mandatory tender for purchase on the occurrence of certain events. These bonds include:

(in millions)		
Jefferson Co. 2001 Series A, due September 1, 2026, variable %	$	22
Trimble Co. 2001 Series A, due September 1, 2026, variable %		28
Jefferson Co. 2001 Series B, due November 1, 2027, variable %		35
Trimble Co. 2001 Series B, due November 1, 2027, variable %		35
	$	120

The average annualized interest rates for these bonds follow:

	September 30, 2010	September 30, 2009
Three months ended	1.10%	1.04%
Nine months ended	0.90%	1.11%

Pollution control bonds are obligations of LG&E issued in connection with tax-exempt pollution control bonds issued by various governmental entities, principally counties in Kentucky. A loan agreement obligates the Company to make debt service payments to the governmental entities that equate to the debt service due from the entities on the related pollution control bonds. The loan agreement is an unsecured obligation of the Company. Debt issuance expense is capitalized in either regulatory assets or current or long-term other assets and amortized over the lives of the related bond issues, consistent with regulatory practices.

In October 2010, LG&E's pollution control bonds were converted from unsecured debt to debt which is collateralized by first mortgage bonds. Also in October 2010, two national rating agencies revised the credit ratings of the pollution control bonds. One revised downward the short-term credit rating of the pollution control bonds and the Company's issuer rating as a result of the pending acquisition by PPL, and the other increased the long-term rating of the pollution control bonds as a result of the addition of the first mortgage bonds as collateral.

Several of the LG&E pollution control bonds are insured by monoline bond insurers whose ratings have been reduced due to exposures relating to insurance of sub-prime mortgages. At September 30, 2010, LG&E had an aggregate $574 million (including $163 million of reacquired bonds) of outstanding pollution control indebtedness, of which $135 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. Since 2008, the Company experienced "failed auctions" when there were insufficient bids for the bonds. When a failed auction occurs, the interest rate is set pursuant to a formula stipulated in the indenture.

The average annualized interest rates on the auction rate bonds follow:

	September 30, 2010	September 30, 2009
Three months ended	0.49%	0.38%
Nine months ended	0.44%	0.42%

The instruments governing these auction rate bonds permit LG&E 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 June 2009, one national rating agency downgraded the credit rating of an insurer of the Company's bonds. As a result, the national rating agency downgraded the ratings on the Trimble County 2000 Series A, 2002 Series A and 2007 Series A; Jefferson County 2001 Series A; and Louisville Metro 2007 Series B bonds. The national agency's ratings of these bonds are now based on the rating of the Company rather than the rating of the insurer since the Company's rating is higher.

During 2008, LG&E converted several series of its pollution control bonds from the auction rate mode to a weekly interest rate mode, as permitted under the loan documents. In connection with these conversions, the Company purchased the bonds from the remarketing agent. For financial reporting purposes, the repurchase of the bonds was accounted for as debt extinguishments. As of September 30, 2010 and December 31, 2009, the Company continued to hold repurchased bonds in the amount of $163 million, and therefore, such amount is excluded from the Company's balance sheets. The other repurchased bonds were remarketed during 2008 in an intermediate-term fixed rate mode wherein the interest rate is reset periodically (every three to five years). LG&E will hold some or all of such repurchased bonds until a later date, at which time it may refinance, remarket or further convert such bonds. Uncertainty in markets relating to auction rate securities or steps the Company has taken or may take to mitigate such uncertainty, such as additional conversion, subsequent restructuring or redemption and refinancing, could result in increased interest expense, transaction expenses or other costs and fees or experiencing reduced liquidity relating to existing or future pollution control financing structures.

The Company participates in an intercompany money pool agreement wherein E.ON U.S. and/or KU make funds available to LG&E 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
September 30, 2010	$ 400	$ 122	$ 278	0.28%
December 31, 2009	$ 400	$ 170	$ 230	0.20%

E.ON U.S. maintained revolving credit facilities totaling $313 million at September 30, 2010 and December 31, 2009, to ensure funding availability for the money pool. At September 30, 2010, one facility, totaling $150 million, was with E.ON North America, Inc. while the remaining line, totaling $163 million, was with Fidelia; both are affiliated companies. The balances are as follows:

(in millions)	Total Available	Amount Outstanding	Balance Available	Average Interest Rate
September 30, 2010	$ 313	$ 181	$ 132	1.44%
December 31, 2009	$ 313	$ 276	$ 37	1.25%

As of September 30, 2010, the Company maintained $125 million bilateral lines of credit, maturing in June 2012, with unaffiliated financial institutions. At September 30, 2010, there was no balance outstanding under any of these facilities.

There were no redemptions or issuances of long-term debt year-to-date through September 30, 2010. LG&E was in compliance with all debt covenants at September 30, 2010 and December 31, 2009. See Note 1, General, for certain debt refinancing and associated transactions which are anticipated by LG&E in connection with the PPL acquisition and Note 11, Related Party Transactions, for long-term debt payable to affiliates.

Note 9 – Commitments and Contingencies

Except as may be discussed in this quarterly report (including Note 2, Rates and Regulatory Matters), material changes have not occurred in the current status of various commitments or contingent liabilities from that discussed in the Company's Annual Report for the year ended December 31, 2009 (including, but not limited to Note 2, Rates and Regulatory Matters; Note 9, Commitments and Contingencies; and Note 14, Subsequent Events, contained therein). See the Company's Annual Report regarding such commitments or contingencies.

Letters of Credit

LG&E has provided letters of credit as of September 30, 2010 and December 31, 2009, for off-balance sheet obligations totaling $3 million to support certain obligations related to landfill reclamation and letters of credit for off-balance sheet obligations totaling less than $1 million to support certain obligations related to workers' compensation.

Construction Program

LG&E had approximately $179 million of commitments in connection with its construction program at September 30, 2010.

In June 2006, the Companies 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. During 2009 and 2010, the Companies received several contractual notices from the TC2 construction contractor asserting historical force majeure and excusable event claims for a number of adjustments to the contract price, construction schedule, commercial operations date, liquidated damages or other relevant provisions. In September 2010, the Companies and the construction contractor agreed to a settlement to resolve certain force majeure and excusable event claims occurring through July 2010, under the TC2 construction contract, which settlement provided for a limited, negotiated extension of the contractual commercial operations date and/or relief from liquidated damages calculations. During commissioning activities in the second and third quarters, separate delays have occurred related to burner malfunctions and an excitation transformer failure. Certain temporary or permanent repairs for both matters have been completed, are underway or are planned for appropriate future outage periods. Commissioning steps resumed in October 2010, and a revised commercial operations date is currently expected by year end. The parties are analyzing the treatment of these additional delays under the liquidated damages provisions of the construction agreement. The Companies cannot currently estimate the ultimate outcome of these matters, including the extent, if any, that such outcome may result in materially increased costs for the construction of TC2, further changes in the TC2 construction completion or commercial operation dates or potential effects on levels of power purchases or wholesale sales due to such changed dates.

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. In September 2007, the Secretary of the Kentucky Environmental and Public Protection Cabinet issued a final Order upholding the permit. The environmental groups petitioned the EPA to object to the state permit and subsequent permit revisions. In determinations made in September 2008 and June 2009, the EPA rejected most of the environmental groups' claims, but identified three permit deficiencies which the KDAQ addressed by revising the permit. In August 2009, the EPA issued an Order denying the remaining claims with the exception of two additional deficiencies which the KDAQ was directed to address. The EPA determined that the proposed permit subsequently issued by the KDAQ satisfied the conditions of the EPA Order although the agency recommended certain enhancements to the administrative record. In January 2010, the KDAQ issued a final permit revision incorporating the proposed changes to address the EPA objections. In March 2010, the environmental groups submitted a petition to the EPA to object to the permit revision, which is now pending before the EPA. The Company believes that the final permit as revised should not have a material adverse effect on its financial condition or results of operations. However, until the EPA issues a final ruling on the pending petition and all applicable appeals have been exhausted, the Company cannot predict the final outcome of this matter.

Thermostat Replacement

During January 2010, the Companies announced a voluntary plan to replace certain thermostats, which had been provided to customers as part of the Companies' demand reduction programs, due to concerns that the thermostats may present a safety hazard. Under the plan, the Companies have replaced approximately 90% of the estimated 14,000 thermostats that need to be replaced. Total estimated costs associated with the replacement program are $2 million. However, the Companies cannot fully predict the ultimate outcome of the replacement program or other effects or developments which may be associated with the thermostat replacement matter at this time.

OVEC

LG&E holds a 5.63% investment interest in OVEC with 10 other electric utilities. LG&E is not the primary beneficiary; therefore the investment is not consolidated into the Company's financial statements, but is recorded on the cost basis. OVEC is located in Piketon, Ohio, and owns and operates two coal-fired power plants, Kyger Creek Station in Ohio, and Clifty Creek Station in Indiana. LG&E is contractually entitled to 5.63% of OVEC's output, approximately 124 Mw of generation capacity. Pursuant to the OVEC power purchase contract, the Company may be conditionally responsible for a 5.63% pro-rata share of certain obligations of OVEC under defined circumstances. These contingent liabilities may include unpaid OVEC indebtedness as well as shortfall amounts in certain excess decommissioning costs and post-retirement benefits other than pension. LG&E's potential proportionate share of OVEC's September 30, 2010 outstanding debt was $78 million.

Environmental Matters

The Company's operations are subject to a number of environmental laws and regulations 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. As indicated below and summarized at the conclusion of this section, evolving environmental regulations will likely increase the level of capital and operating and maintenance expenditures incurred by the Company during the next several years. Based on prior regulatory precedent, the Company believes that many costs of complying with such pending or future requirements would likely be recoverable under the ECR or other potential cost-recovery mechanisms, but the Company can provide no assurance as to the ultimate outcome of such proceedings before the regulatory authorities.

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.

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 place in the interim. The remand of the CAIR results in some uncertainty with respect to certain other EPA or state programs and proceedings and the Companies' compliance plans relating thereto due to the interconnection of the CAIR with such associated programs.

In January 2010, the EPA proposed a revised NAAQS for ozone which would increase the stringency of the standard. In addition, the EPA published final revised NAAQS standards for nitrogen dioxide ("NO_2") and SO_2 in February 2010 and June 2010, respectively, which are more stringent than previous standards. Depending on the level of action determined necessary to bring local nonattainment areas into compliance with the revised NAAQS standards, LG&E's power plants are potentially subject to requirements for additional reductions in SO_2 and NOx emissions.

In July 2010, the EPA issued the proposed CATR, which serves to replace the CAIR. The CATR provides for a two-phase SO_2 reduction program with Phase I reductions due by 2012, and Phase II reductions due by 2014. The CATR provides for NOx reductions in 2012, but the EPA advised that it is studying whether additional NOx reductions should be required for 2014. The CATR is more stringent than the CAIR as it accelerates certain compliance dates and provides for only intrastate and limited interstate trading of emission allowances. In addition to its preferred approach, the EPA is seeking comment on an alternative approach which would provide for individual emission limits at each power plant. The EPA has announced that it will propose additional "transport" rules to address compliance with revised NAAQS standards for ozone and particulate matter which will be issued by the EPA in the future, as discussed below.

Hazardous Air Pollutants. As provided in 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 addition, in 2006, the Metro Louisville Air Pollution Control District adopted rules aimed at regulating additional hazardous air pollutants from sources including power plants.

In February 2008, a federal appellate court issued a decision vacating the CAMR. The EPA has entered into a consent decree requiring it to promulgate a utility Maximum Achievable Control Technology rule to replace the CAMR with a proposed rule due by March 2011, and a final rule due by November 2011. Depending on the final outcome of the rulemaking, the CAMR could be replaced by new rules with different or more stringent requirements for reduction of mercury and other hazardous air pollutants. Kentucky has also repealed its corresponding state mercury regulations.

Acid Rain Program. 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 Clean Air Act also contains 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 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 the 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. LG&E had previously installed FGD equipment on all of its generating units prior to the effective date of the acid rain program. LG&E's strategy for its Phase II SO_2 requirements, which commenced in 2000, is to use accumulated emission allowances to defer additional capital expenditures and continue to evaluate improvements to further reduce SO_2 emissions. In order to achieve the NOx emission reductions mandated by the NOx SIP Call, LG&E installed additional NOx controls, including SCR technology, during the 2000 through 2009 time period at a cost of $197 million. In 2001, the Kentucky Commission granted approval to recover the costs incurred by LG&E for these projects through the ECR mechanism. Such monthly recovery is subject to periodic review by the Kentucky Commission.

In order to achieve currently mandated emissions reductions, LG&E expects to incur additional capital expenditures totaling approximately $80 million during the 2010 through 2012 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. LG&E believes its costs in reducing SO_2, NOx and mercury emissions to be comparable to those of similarly situated utilities with like generation assets. LG&E'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. LG&E 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.

GHG Developments. 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. As discussed below, 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, 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. The current administration has announced its support for the adoption of mandatory GHG reduction requirements at the federal level. The United States and other countries met in Copenhagen, Denmark in December 2009, in an effort to negotiate a GHG reduction treaty to succeed the Kyoto Protocol, which is set to expire in 2013. In Copenhagen, the U.S. made a nonbinding commitment to, among other things, seek to reduce GHG emissions to 17% below 2005 levels by 2020 and provide financial support to developing countries. The United States and other nations are scheduled to meet in Cancun, Mexico in late 2010 to continue negotiations toward a binding agreement.

GHG Legislation. LG&E is monitoring on-going efforts to enact GHG reduction requirements and requirements governing carbon sequestration at the state and federal level and is assessing potential impacts of such programs and strategies to mitigate those impacts. In June 2009, the U.S. House of Representatives passed the American Clean Energy and Security Act of 2009, which is a comprehensive energy bill containing the first-ever nation-wide GHG cap and trade program. The bill would provide for reductions in GHG emissions of 3% below 2005 levels by 2012, 17% by 2020 and 83% by 2050. In order to cushion potential rate impacts for utility customers, approximately 43% of emissions allowances would initially be allocated at no cost to the electric utility sector, with this allocation gradually declining to 7% in 2029 and zero thereafter. The bill would also establish a renewable electricity standard requiring utilities to meet 20% of their electricity demand through renewable energy and energy efficiency by 2020. The bill contains additional provisions regarding carbon capture and sequestration, clean transportation, smart grid advancement, nuclear and advanced technologies and energy efficiency.

In September 2009, the Clean Energy Jobs and American Power Act, which is largely patterned on the House legislation, was introduced in the U.S. Senate. The Senate bill raises the emissions reduction target for 2020 to 20% below 2005 levels and does not include a renewable electricity standard. While the initial bill lacked detailed provisions for the allocation of emissions allowances, a subsequent revision incorporated allowance allocation provisions similar to the House bill. In 2010, Senators Kerry and Lieberman and others have undertaken additional work to draft GHG legislation but have introduced no bill in the Senate to date. In July 2010, Senate Majority Leader Reid announced that he did not anticipate that GHG legislation would be brought to the Senate floor in the current session. The Company is closely monitoring the progress of pending energy legislation, but the prospect for passage of comprehensive GHG legislation in 2010 is uncertain.

GHG Regulations. In April 2007, the U.S. Supreme Court ruled that the EPA has the authority to regulate GHG under the Clean Air Act. In April 2009, the EPA issued a proposed endangerment finding concluding that GHGs endanger public health and welfare, which is an initial rulemaking step under the Clean Air Act. A final endangerment finding was issued in December 2009. In September 2009, the EPA issued a final GHG reporting rule requiring reporting by facilities with annual GHG emissions equivalent to at least 25,000 tons of carbon dioxide. A number of the Company's facilities will be required to submit annual reports commencing with calendar year 2010. In May 2010, the EPA issued a final GHG "tailoring" rule requiring new or modified sources with GHG emissions equivalent to at least 75,000 tons of carbon dioxide to obtain permits under the Prevention of Significant Deterioration Program. Such new or modified facilities would be required to install Best Available Control Technology. While the Company is unaware of any currently available GHG control technology that might be required for installation on new or modified power plants, it is currently assessing the potential impact of the rule. The final rule will apply to new and modified power plants beginning in January

2011. The Company is unable to predict whether mandatory GHG reduction requirements will ultimately be enacted through legislation or regulations.

GHG Litigation. A number of lawsuits have been filed asserting common law claims including nuisance, trespass and negligence against various companies with GHG emitting facilities. In October 2009, a three-judge panel of the United States Court of Appeals for the 5th Circuit in the case of Comer v. Murphy Oil reversed a lower court, holding that private plaintiffs have standing to assert certain common law claims against more than 30 utility, oil, coal and chemical companies. In March 2010, the court vacated the opinion of the three-judge panel and granted a motion for rehearing but subsequently denied the appeal due to the lack of a quorum. The appellate ruling leaves in effect the lower court ruling dismissing the plaintiffs' claims. The petitioners filed a petition for a writ of mandamus with the Supreme Court in August 2010. The Comer complaint alleges that GHG emissions from the defendants' facilities contributed to global warming which increased the intensity of Hurricane Katrina. E.ON, the indirect parent of the Companies, was included as defendant in the complaint but has not been subject to the proceedings due to the failure of the plaintiffs to pursue service under the applicable international procedures. The Companies are currently unable to predict further developments in the Comer case and continue to monitor relevant GHG litigation to identify judicial developments that may be potentially relevant to their operations.

Ash Ponds and Coal-Combustion Byproducts. The EPA has undertaken various initiatives in response to the December 2008 impoundment failure at the Tennessee Valley Authority's Kingston power plant, which resulted in a major release of coal combustion byproducts into the environment. The EPA issued information requests to utilities throughout the country, including LG&E, to obtain information on their ash ponds and other impoundments. In addition, the EPA inspected a large number of impoundments located at power plants to determine their structural integrity. The inspections included several of LG&E's impoundments, which the EPA found to be in satisfactory condition except for certain impoundments at the Mill Creek and Cane Run stations, which were determined to be in fair condition. In June 2010, the EPA published proposed regulations for coal combustion byproducts handled in landfills and ash ponds. The EPA has proposed two alternatives: (1) regulation of coal combustion byproducts in landfills and ash ponds as a hazardous waste or (2) regulation of coal combustion byproducts as a solid waste with minimum national standards. Under both alternatives, the EPA has proposed safety requirements to address the structural integrity of ash ponds. In addition, the EPA will consider potential refinements of the provisions for beneficial reuse of coal combustion byproducts.

Water Discharges and PCB Regulations. The EPA has also announced plans to develop revised effluent limitation guidelines governing discharges from power plants and standards for cooling water intake structures. The EPA has further announced plans to develop revised standards governing the use of polychlorinated biphenyls ("PCB") in electrical equipment. The Company is monitoring these ongoing regulatory developments but will be unable to determine the impact until such time as new rules are finalized.

Impact of Pending and Future Environmental Developments. As a company with significant coal-fired generating assets, LG&E will likely be substantially impacted by pending or future environmental rules or legislation requiring mandatory reductions in GHG emissions or other air emissions, imposing more stringent standards on discharges to waterways, or establishing additional requirements for handling or disposal of coal combustion byproducts. These evolving environmental regulations will likely require an increased level of capital expenditures and increased incremental operating and maintenance costs by the Company over the next several years. Due to the uncertain nature of the final regulations that will ultimately be adopted by the EPA, including the reduction targets and the deadlines that will be applicable, the Company cannot finalize estimates of the potential compliance costs, but should the final rules incorporate additional emission reduction requirements, require more stringent emissions controls or implement more stringent byproducts storage and disposal practices, such costs will likely be significant. With respect to NAAQS, CATR, CAMR replacement and coal combustion byproducts developments, based on a preliminary analysis of proposed regulations, the Company may be required to consider actions such as upgrading existing emissions controls, installing additional emissions controls, upgrading byproducts disposal and storage and possible early replacement of coal-fired units. Capital expenditures for LG&E associated with such actions are preliminarily estimated to be in the $2.3 billion range over the next 10 years, although final costs may substantially vary. With respect to potential developments in water discharge, revised PCB standards or GHG initiatives, costs in such areas cannot be estimated due to the preliminary status or uncertain outcome of such developments, but would be in addition to the above amount and could be substantial. Ultimately, the precise impact on the Company's operations of these various environmental developments cannot be determined prior to the finalization of such requirements. Based on prior regulatory precedent, the Company believes that many costs of complying with such pending or future requirements would likely be recoverable under the ECR or other potential cost-recovery mechanisms, but the Company can provide no assurance as to the ultimate outcome of such proceedings before the regulatory authorities.

TC2 Water Permit. In May 2010, the Kentucky Waterways Alliance and other environmental groups filed a petition with the Kentucky Energy and Environment Cabinet challenging the Kentucky Pollutant Discharge Elimination System permit issued in April 2010, which covers water discharges from the Trimble County generating station. In October 2010, the hearing officer issued a report and recommended order providing for dismissal of the claims raised by the petitioners. Until such time as the Secretary issues a final order of the agency and all appeals are exhausted, the Company is unable to predict the outcome or precise impact of this matter.

General Environmental Proceedings. From time to time, LG&E 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 a prior Section 114 information request from the EPA relating to new source review issues at LG&E's Mill Creek Unit 4 and Trimble County Unit 1; remediation obligations or activities for former manufactured gas plant sites or 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 on-going claims regarding alleged particulate emissions from the Company's Cane Run generating station and claims regarding GHG emissions from the Company's generating stations. With respect to the former manufactured gas plant sites, LG&E has estimated that it could incur additional costs of less than $1 million for remaining clean-up activities under existing approved plans or agreements. Based on analysis to date, the resolution of these matters is not expected to have a material impact on the Company's operations.

Note 10 – Segments of Business

LG&E's revenues and net income by business segment were as follows:

	Three Months Ended September 30,		Nine Months Ended September 30,	
(in millions)	2010	2009	2010	2009
Electric:				
Gross/net revenues	$ 297	$ 248	$ 776	$ 711
Net income	$ 59	$ 55	$ 92	$ 70
Gas:				
Gross revenues	$ 32	$ 30	$ 201	$ 276
Intersegment revenues (a)	(2)	(2)	(5)	(6)
Net revenues	$ 30	$ 28	$ 196	$ 270
Net income	$ 1	$ (5)	$ 15	$ 6
Total				
Gross revenues	$ 329	$ 278	$ 977	$ 987
Intersegment revenues (a)	(2)	(2)	(5)	(6)
Net revenues	$ 327	$ 276	$ 972	$ 981
Net income	$ 60	$ 50	$ 107	$ 76

(a) Intersegment revenues were eliminated on consolidation of the electric and gas segments.

LG&E's total assets by business segment were as follows:

(in millions)	September 30, 2010	December 31, 2009
Electric	$ 2,906	$ 2,854
Gas	735	714
Total assets	$ 3,641	$ 3,568

Note 11 – Related Party Transactions

LG&E, subsidiaries of E.ON U.S. and subsidiaries of E.ON engage in related party transactions. Transactions between LG&E and E.ON U.S. subsidiaries are eliminated on consolidation of E.ON U.S. Transactions between LG&E and E.ON subsidiaries are eliminated on consolidation of E.ON. These transactions are generally performed at cost and are in accordance with FERC regulations under the Public Utility Holding Company Act of 2005 and the applicable Kentucky Commission regulations. The significant related party transactions are disclosed below.

Intercompany Wholesale Sales and Purchases

LG&E and KU jointly dispatch their generation units with the lowest cost generation used to serve their retail native load. When LG&E has excess generation capacity after serving its own retail native load and its generation cost is lower than that of KU, KU purchases electricity from LG&E. When KU has excess generation capacity after serving its own retail native load and its generation cost is lower than that of LG&E, LG&E purchases electricity from KU. These transactions are recorded as intercompany wholesale sales and purchases are recorded by each company at a price equal to the seller's fuel cost. Savings realized from purchasing electricity intercompany instead of generating from their own higher costs units or purchasing from the market are shared equally between the two Companies. The volume of energy each company has to sell to the other is dependent on its native load needs and its available generation.

These sales and purchases are included in the statements of income as electric operating revenues, power purchased expenses and other operation and maintenance expenses. LG&E's intercompany electric revenues and power purchased expense were as follows:

	Three Months Ended September 30,		Nine Months Ended September 30,	
(in millions)	2010	2009	2010	2009
Electric operating revenues from KU	$ 22	$ 22	$ 71	$ 82
Power purchased and related operations and maintenance expense from KU	3	2	13	18

Interest Charges

See Note 8, 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.

LG&E's interest expense to affiliated companies was as follows:

	Three Months Ended September 30,		Nine Months Ended September 30,	
(in millions)	2010	2009	2010	2009
Interest on money pool loans (a)	$ -	$ 1	$ -	$ 1
Interest on Fidelia loans	6	5	20	19

(a) Interest expense paid to E.ON U.S. on the money pool arrangement was less than $1 million for the three and nine months ended September 30, 2010.

Dividends

In March and September 2010, the Company paid dividends of $30 million and $25 million, respectively, to its common shareholder, E.ON U.S. In March and June 2009, the Company paid dividends of $35 million and $45 million, respectively, to its common shareholder, E.ON U.S.

Other Intercompany Billings

Servco provides the Company with a variety of centralized administrative, management and support services. These services include payroll taxes paid by Servco on behalf of LG&E, labor and burdens of Servco employees performing services for LG&E, coal purchases and other vouchers paid by Servco on behalf of LG&E. The cost of these services is directly charged to the Company, 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, the Companies provide services to each other and to Servco. Billings between the Companies relate to labor and overheads associated with union and hourly employees performing work for the other utility, charges related to jointly-owned generating units and other miscellaneous charges. Billings from LG&E to Servco include cash received by Servco on behalf of LG&E, primarily tax settlements, and other payments made by the Company on behalf of other non-regulated businesses which are reimbursed through Servco.

Intercompany billings to and from LG&E were as follows:

	Three Months Ended September 30,		Nine Months Ended September 30,	
(in millions)	2010	2009	2010	2009
Servco billings to LG&E	$ 54	$ 37	$ 169	$ 132
LG&E billings to KU	28	-	47	-
KU billings to LG&E	-	16	1	63
LG&E billings to Servco	12	1	16	1

Intercompany Balances

The Company had the following balances with its affiliates:

(in millions)	September 30, 2010	December 31, 2009
Accounts receivable from KU	$ 17	$ 53
Accounts payable to Servco	16	18
Accounts payable to E.ON U.S.	14	4
Accounts payable to Fidelia	9	6
Notes payable to E.ON U.S.	122	170
Long-term debt to Fidelia	485	485

Note 12 – Subsequent Events

Subsequent events have been evaluated through October 29, 2010, the date of issuance of these statements, and these statements contain all necessary adjustments and disclosures resulting from that evaluation.

On October 26, 2010, the FERC issued an Order approving the acquisition of E.ON U.S. by PPL. See Note 1, General.

On October 22, 2010, LG&E's pollution control bonds were converted from unsecured debt to debt which is collateralized by first mortgage bonds. See Note 1, General, and Note 8, Short-Term and Long-Term Debt.

On October 19, 2010 and October 21, 2010, respectively, the Virginia Commission and Tennessee Regulatory Authority issued Orders approving the acquisition of E.ON U.S. by PPL. See Note 1, General.

Management's Discussion and Analysis

Overview

LG&E, incorporated in Kentucky in 1913, is a regulated public utility engaged in the generation, transmission, distribution and sale of electric energy and the storage, distribution and sale of natural gas. LG&E provides electric service to approximately 396,000 customers in Louisville and adjacent areas in Kentucky covering approximately 700 square miles in 9 counties. Natural gas service is provided to approximately 320,000 customers in its electric service area and 8 additional counties in Kentucky. Approximately 94% of the electricity generated by LG&E is produced by its coal-fired electric generating stations, all equipped with systems to reduce SO_2 emissions. The remainder is generated by a hydroelectric power plant and natural gas and oil fueled combustion turbines. Underground natural gas storage fields help LG&E provide economical and reliable natural gas service to customers.

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

The following discussion and analysis by management focuses on those factors that had a material effect on LG&E's financial results of operations and financial condition during the three and nine months ended September 30, 2010, and should be read in connection with the condensed financial statements and notes thereto and the Annual Report for the year ending December 31, 2009. Dollars are in millions unless otherwise noted.

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, 2009.

PPL Acquisition

See Note 1, General, for information regarding the acquisition of E.ON U.S. by PPL, settlement agreements in change of control proceedings, closing conditions and anticipated financing transactions.

See Note 8, Short-Term and Long-Term Debt, for further information regarding the refinancing, remarketing or conversion of existing pollution control debt.

Regulatory Matters

See Note 2, Rates and Regulatory Matters, for information regarding rate cases, regulatory assets and liabilities and other regulatory matters.

Environmental Matters

General

Protection of the environment is a major priority for LG&E and a significant element of its business activities. LG&E's properties and operations are subject to extensive environmental-related oversight by federal, state and local regulatory agencies, including via air quality, water quality, waste management and similar laws and regulations. Therefore, LG&E must conduct its operations in accordance with numerous permit and other requirements issued under or contained in such laws or regulations.

Climate Change

Recent developments continue to indicate an increased possibility of significant climate change or GHG legislation or regulation, at the international, federal, regional and state levels. During December 2009, as part of the United Nation's Copenhagen Accord, the United States agreed to a non-binding goal to reduce GHG emissions to 17% below 2005 levels by 2020. Additionally, during 2009, the U.S. House of Representatives passed comprehensive GHG legislation, which included a number of measures to limit GHG emissions and achieve GHG emission reduction targets below 2005 levels of 3% by 2012, 17% by 2020, and 83% by 2050. Similar legislation has been considered in the U.S. Senate, but the prospects for passage remain uncertain. In late 2009, the EPA issued or proposed various regulatory initiatives relating to GHG matters, including an endangerment finding relating to mobile sources of GHGs, a GHG reporting requirement and a rule relating to permitting requirements for new or modified GHG emission sources. Finally, a number of U.S. states, although not currently including Kentucky, have adopted GHG-reduction legislation or regulation of various sorts. The developing GHG initiatives include a number of differing structures and formats, including direct limitations on GHG sources, issuance of allowances for GHG emissions, cap-and-trade programs for such allowances, renewable or alternative generation portfolio standards and mechanisms relating to demand reduction, energy efficiency, smart-grid, transmission expansion, carbon-sequestration or other GHG-reducing efforts. While the final terms and impacts of such initiatives cannot be estimated, LG&E, as a primarily coal-fired utility, could be highly affected by such proceedings.

Other Environmental Regulatory Initiatives

Additionally, the EPA has proposed or announced that it intends to propose a number of additional environmental regulations that could substantially impact utilities with coal-fired generating assets. These regulatory initiatives include revisions to the ambient air quality standards for SO_2, NO_2, ozone, and particulate matter 2.5 microns in size or less, rules aimed at mitigating the interstate transport of SO_2 and NOx, a program governing emissions of hazardous air pollutants from utility generating units, a program for the management of coal combustion residuals, revised effluent guidelines for utility generating facilities and standards for water intake structures. Such requirements could potentially mandate upgrade of existing emission controls, installation of additional emission controls such as FGDs, SCRs, fabric filter bag houses, activated carbon injection, wet electrostatic precipitators, closure of ash ponds and retrofit of landfills, installation of cooling towers, deployment of new water treatment technologies and retirement of facilities that cannot be retrofitted on a cost effective basis.

The cost to LG&E and the effect on LG&E's business of complying with potential GHG restrictions and other environmental regulatory initiatives will depend on the details of the programs ultimately enacted.

Some of the design elements which may have the greatest effect on LG&E include (a) the required levels and timing of emissions caps, discharge limits or similar standards (b) the sources covered by such requirements, (c) transition and mitigation provisions, such as phase-in periods, free allowances or price caps, (d) the availability and pricing of relevant mitigation or control technologies, goods or services and (e) economic, market and customer reaction to electricity price and demand changes due to environmental concerns.

Ultimately, environmental matters or potential environmental matters can represent an important element of current or future potential capital requirements, future unit retirement or replacement decisions, supply and demand for electricity, operating and maintenance expenses or compliance risks for the Company. Based on prior regulatory precedent, LG&E currently anticipates that many of such direct costs may be recoverable through rates or other regulatory mechanisms, particularly with respect to coal-related generation, but the availability, timing or completeness of such rate recovery cannot be assured. Ultimately, climate change and other environmental matters will likely increase the level of capital expenditures and operating and maintenance costs incurred by the Company during the next several years. With respect to NAAQS, CATR, CAMR replacement and coal combustion byproducts developments, based on a preliminary analysis of proposed regulations, the Company may be required to consider actions such as upgrading existing emissions controls, installing additional emissions controls, upgrading byproducts disposal and storage and possible early replacement of coal-fired units. Capital expenditures for LG&E associated with such actions are preliminarily estimated to be in the $2.3 billion range over the next 10 years, although final costs may substantially vary. See Management's Discussion and Analysis and Note 9, Commitments and Contingencies, for additional information.

Results of Operations

The electric and gas 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, 2010, Compared to
Three Months Ended September 30, 2009

Net Income

Net income was $60 million for the three months ended September 30, 2010, compared to $50 million for the same period in 2009. The increase was primarily the result of the following:

	Three Months Ended September 30, 2010	Three Months Ended September 30, 2009	Increase (Decrease)
Total operating revenues	$ 327	$ 276	$ 51
Total operating expenses	250	182	68
Operating income	77	94	(17)
Derivative gain (loss)	29	(4)	33
Interest expense	5	5	-
Interest expense to affiliated companies	6	6	-
Income before income taxes	95	79	16
Income tax expense	35	29	6
Net income	$ 60	$ 50	$ 10

Net income attributable by segment was:

	Three Months Ended September 30, 2010	Three Months Ended September 30, 2009	Increase (Decrease)
Electric	$ 59	$ 55	$ 4
Gas	1	(5)	6
Total	$ 60	$ 50	$ 10

Operating Revenues

Operating revenues follow:

	Three Months Ended September 30, 2010	2009	Increase (Decrease)
Electric revenues	$ 297	$ 248	$ 49
Gas revenues	30	28	2
Total operating revenues	$ 327	$ 276	$ 51

Revenues

The $51 million increase in revenues in the three months ended September 30, 2010, was primarily due to:

	Increase (Decrease)
Retail sales volumes (a)	$ 29
Retail electric base rates (b)	16
Retail FAC costs billed to customers due to higher fuel price	6
	$ 51

(a) Primarily due to increased consumption by residential customers as a result of increased cooling degree days and higher energy usage by industrial customers as a result of improved economic conditions and increased cooling degree days.

(b) Due to higher rates effective August 1, 2010. See Note 2, Rates and Regulatory Matters, for further discussion of the 2010 electric and gas rate cases.

Operating Expenses

Fuel for electric generation and natural gas supply expense comprise a large component of total operating expenses. Increases or decreases in the costs of fuel and natural gas supply are reflected in retail rates through the FAC and GSC, subject to the approval of the Kentucky Commission. Operating expenses follow:

	Three Months Ended September 30, 2010	2009	Increase (Decrease)
Fuel for electric generation	$ 104	$ 83	$ 21
Power purchased	12	10	2
Gas supply expenses	10	10	-
Other operation and maintenance expenses	89	44	45
Depreciation, accretion and amortization	35	35	-
Total operating expenses	$ 250	$ 182	$ 68

Fuel for Electric Generation

The $21 million increase in fuel for electric generation in the three months ended September 30, 2010, was primarily due to:

	Increase (Decrease)
Commodity and transportation costs for coal	$ 14
Fuel usage due to increased retail sales volumes	7
	$ 21

Other Operation and Maintenance Expenses

Other operation and maintenance expenses increased $45 million in the three months ended September 30, 2010, due to $43 million of increased maintenance expenses and $2 million of increased other operation expenses. These increases were primarily due to distribution expenses ($42 million related to maintenance and $2 million related to other operations) incurred in the first quarter of 2009 for wind and ice storm restoration that were reclassified to a regulatory asset in the third quarter of 2009.

Derivative Gain (Loss)

The $33 million increase in derivative gain (loss) in the three months ended September 30, 2010, was primarily due to:

	Increase (Decrease)
Reclassification of ineffective interest rate swap loss to a regulatory asset in 2010 (a)	$ 21
Reclassification of terminated interest rate swap loss to a regulatory asset in 2010 (a)	9
Loss on ineffective interest rate swaps in 2009	3
	$ 33

(a) See Note 2, Rates and Regulatory Matters, for further discussion of the interest rate swap regulatory assets.

Income Tax Expense

See Note 7, Income Taxes, for a reconciliation of differences between the U.S. federal income tax expense at statutory rates and LG&E's income tax expense.

Nine Months Ended September 30, 2010, Compared to
Nine Months Ended September 30, 2009

Net Income

Net income was $107 million for the nine months ended September 30, 2010, compared with $76 million for the same period in 2009. The increase was primarily the result of the following:

	Nine Months Ended September 30, 2010	Nine Months Ended September 30, 2009	Increase (Decrease)
Total operating revenues	$ 972	$ 981	$ (9)
Total operating expenses	788	842	(54)
Operating income	184	139	45
Derivative gain (loss)	18	12	6
Interest expense	14	13	(1)
Interest expense to affiliated companies	20	20	-
Other income (expense) – net	(1)	(1)	-
Income before income taxes	167	117	50
Income tax expense	60	41	19
Net income	$ 107	$ 76	$ 31

Net income attributable by segment was:

	Nine Months Ended September 30, 2010	Nine Months Ended September 30, 2009	Increase (Decrease)
Electric	$ 92	$ 70	$ 22
Gas	15	6	9
Total	$ 107	$ 76	$ 31

Operating Revenues

Operating revenues follow:

	Nine Months Ended September 30, 2010	Nine Months Ended September 30, 2009	Increase (Decrease)
Electric	$ 776	$ 711	$ 65
Gas	196	270	(74)
Total operating revenues	$ 972	$ 981	$ (9)

Electric Revenues

The $65 million increase in electric revenues in the nine months ended September 30, 2010, was primarily due to:

	Increase (Decrease)
Retail sales volumes (a)	$ 55
Retail base rates (b)	13
Retail FAC costs billed to customers due to higher fuel price	11
DSM revenue due to increased recoverable program spending	6
Wholesale sales to KU due to volume (c)	(13)
Wholesale sales to third parties due to volume (d)	(7)
	$ 65

(a) Primarily due to increased consumption by residential customers as a result of increased cooling and heating degree days and higher energy usage by industrial customers as a result of improved economic conditions and increased cooling and heating degree days.

(b) Primarily due to higher rates effective August 1, 2010. See Note 2, Rates and Regulatory Matters, for further discussion of the 2010 electric and gas rate cases.

(c) Primarily due to increased consumption by residential customers as a result of increased cooling and heating degree days and increased coal-fired generation outages in the first six months of 2010 and higher energy usage by industrial customers as a result of improved economic conditions and increased cooling and heating degree days. See Note 11, Related Party Transactions, for further discussion of the mutual agreement for wholesale sales and purchases between the Companies.

(d) Primarily due to increased consumption by residential customers as a result of increased cooling and heating degree days, increased coal-fired generation outages in the first six months of 2010 and higher energy usage by industrial customers as a result of improved economic conditions and increased cooling and heating degree days.

Gas Revenues

The $74 million decrease in gas revenues in the nine months ended September 30, 2010, was primarily due to:

	Increase (Decrease)
Retail average cost billed through GSC (a)	$ (87)
WNA revenues	(3)
Retail sales volumes (b)	10
Retail base rates (c)	6
	$ (74)

(a) Due to reductions in gas prices as a result of lower fuel costs.
(b) Primarily due to increased consumption by residential customers as a result of increased heating degree days.
(c) Primarily due to higher rates effective August 1, 2010. See Note 2, Rates and Regulatory Matters, for further discussion of the 2010 electric and gas rate cases.

Operating Expenses

Fuel for electric generation and gas supply expenses comprise a large component of total operating expenses. Increases or decreases in the costs of fuel and gas supply are reflected in retail rates through the FAC and GSC, subject to the approval of the Kentucky Commission. Operating expenses follow:

	Nine Months Ended September 30, 2010	Nine Months Ended September 30, 2009	Increase (Decrease)
Fuel for electric generation	$ 277	$ 257	$ 20
Power purchased	41	43	(2)
Gas supply expenses	103	189	(86)
Other operation and maintenance expenses	263	251	12
Depreciation, accretion and amortization	104	102	2
Total operating expenses	$ 788	$ 842	$ (54)

Fuel for Electric Generation

The $20 million increase in fuel for electric generation in the nine months ended September 30, 2010, was primarily due to:

	Increase (Decrease)
Commodity and transportation costs for coal	$ 15
Fuel usage volumes due to increased native load sales	5
	$ 20

Gas Supply Expenses

The $86 million decrease in gas supply expenses in the nine months ended September 30, 2010, was primarily due to:

	Increase (Decrease)
Cost of gas supply billed to customers	$ (96)
Natural gas volumes delivered to retail customers (a)	9
Wholesale sales	1
	$ (86)

(a) Primarily due to increased consumption by residential customers as a result of increased heating degree days.

Other Operation and Maintenance Expenses

Other operation and maintenance expenses increased $12 million in the nine months ended September 30, 2010, primarily due to $11 million of increased boiler and electric maintenance expenses mainly related to outage work and $1 million of increased other operation expenses.

Derivative Gain (Loss)

The $6 million increase in derivative gain (loss) in the nine months ended September 30, 2010, was primarily due to:

	Increase (Decrease)
Reclassification of ineffective interest rate swap loss to a regulatory asset in 2010 (a)	$ 21
Reclassification of terminated interest rate swap loss to a regulatory asset in 2010 (a)	9
Loss on ineffective interest rate swaps (b)	(24)
	$ 6

(a) See Note 2, Rates and Regulatory Matters, for further discussion of the interest rate swap regulatory assets.
(b) Primarily due to a loss in 2010, versus a gain in 2009.

Income Tax Expense

See Note 7, Income Taxes, for a reconciliation of differences between the U.S. federal income tax expense at statutory rates and LG&E's income tax expense.

Financial Condition

Liquidity and Capital Resources

	September 30, 2010	December 31, 2009
Cash and cash equivalents	$ 4	$ 5
Current portion of long-term bonds	120	120
Notes payable to affiliated company	122	170

Activity in LG&E's cash and cash equivalents in the nine months ended September 30, 2010, included the following:

	Increase (Decrease)
Cash provided by operating activities	$ 162
Construction expenditures	(108)
Proceeds from assets sold to affiliate	48
A net decrease in short-term borrowings from affiliated company	(48)
Payments of dividends	(55)
	$ (1)

Working Capital Deficiency

As of September 30, 2010, LG&E had a working capital deficiency of $105 million, primarily due to short-term debt from affiliates associated with the repurchase of certain of its tax-exempt bonds totaling $163 million and $120 million of tax-exempt bonds which allow the investors to put the bonds back to the Company causing them to be classified as current portion of long-term debt. The Company has adequate liquidity facilities to repurchase any bonds put back to the Company. The repurchased bonds are being held until they can be refinanced or restructured. Working capital deficiencies can be funded through an intercompany money pool agreement or through bilateral lines of credit. See Note 8, Short-Term and Long-Term Debt. LG&E believes that its sources of funds will be sufficient to meet the needs of its business in the foreseeable future.

Auction Rate Securities

Auctions for auction rate securities issued by LG&E continued to fail during the quarter. LG&E held $163 million of its own securities at September 30, 2010 and December 31, 2009, that at one time were auction rate securities. See Note 8, Short-Term and Long-Term Debt, for further discussion of auction rate securities.

Debt

Regulatory approvals are required for LG&E to incur additional debt. The FERC authorizes the issuance of short-term debt while the Kentucky Commission authorizes the issuance of long-term debt. In November 2009, LG&E received a two-year authorization from the FERC to borrow up to $400 million in short-term funds. These short-term funds are made available via the Company's participation in an intercompany money pool agreement wherein E.ON U.S. and/or KU make funds available to LG&E at market-based rates (based on highly rated commercial paper issues).

A significant portion of LG&E's short-term debt balance ($163 million) is for borrowings incurred to repurchase auction rate tax-exempt bonds. Following the repurchase, the repurchased bonds have been removed from the balance sheet. However, these bonds are being held until they can be refinanced or restructured.

See Note 1, General, for information on PPL related financing activities and Note 8, Short-Term and Long-Term Debt, for information on redemptions, maturities and issuances of long-term debt.

Common Stock Dividends

In March and September 2010, the Company paid dividends of $30 million and $25 million, respectively, to its common shareholder, E.ON U.S. LG&E uses net cash generated from its operations and external financing (including financing from affiliates) to fund the payment of dividends. Future dividends, declared at the discretion of the Board of Directors, will be dependent on future earnings, financial requirements and other factors.

Credit Ratings

LG&E's credit ratings reflect the views of two national rating agencies. 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. In October 2010, two national rating agencies revised credit ratings of the pollution control bonds. One revised downward the short-term credit rating of the pollution control bonds and the Company's issuer rating as a result of the pending acquisition by PPL, and the other increased the long-term rating of the pollution control bonds as a result of the addition of the first mortgage bonds as collateral. See Note 8, Short-Term and Long-Term Debt, for a discussion of downgrade actions related to the pollution control bonds caused by a change in the rating of the entity insuring those bonds.

LG&E has various derivative and non-derivative contracts, including contracts for the sale and purchase of electricity and fuel, natural gas and interest rate instruments, which contain provisions requiring LG&E to post additional collateral or permit the counterparty to terminate the contract if LG&E's credit rating were to fall below investment grade. At September 30, 2010, if LG&E's credit rating had been below investment grade, the Company would have been required to post an additional $4 million of collateral to counterparties for both derivative and non-derivative commodity and commodity-related contracts used in its generation, marketing and trading operations and interest rate contracts.

Future Capital Requirements

LG&E'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. LG&E expects its capital expenditures for the three year period ending December 31, 2012, to total approximately $815 million, consisting primarily of the following:

Construction of distribution assets	$	355
Construction of generation assets		330
Redevelopment of Ohio Falls hydroelectric facility		60
Information technology projects		35
Other projects		30
Construction of TC2		5
	$	815

In addition to the amounts in the table shown above, evolving environmental regulations will likely increase the level of capital expenditures above the amounts currently expected over the next several years. With respect to NAAQS, CATR, CAMR replacement and coal combustion byproducts developments, based on a preliminary analysis of proposed regulations, the Company may be required to consider actions such as upgrading existing emissions controls, installing additional emissions controls, upgrading byproducts disposal and storage and possible early replacement of coal-fired units. Capital expenditures for LG&E associated with such actions are preliminarily estimated to be in the $2.3 billion range over the next 10 years, although final costs may substantially vary. See Note 9, Commitments and Contingencies, for further discussion of environmental matters. 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. Credit market conditions can affect aspects of the availability, terms or methods in which LG&E and KU fund their capital requirements. LG&E and KU anticipate funding future capital requirements through operating cash flow, debt and/or infusions of capital from their parent.

Controls and Procedures

Management 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 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 condensed 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.

As of December 31, 2009, LG&E 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, management has assessed the effectiveness of the Company's internal control over financial reporting as of December 31, 2009, using the criteria set forth by the Committee of Sponsoring Organizations of the Treadway Commission in *Internal Control – Integrated Framework.* Management has concluded that, as of December 31, 2009, the Company's internal control over financial reporting was effective based on those criteria. There have been no changes in the Company's internal control over financial reporting that occurred during the nine months ended September 30, 2010, that has materially affected or is reasonably likely to materially affect the Company's internal control over financial reporting.

The effectiveness of the Company's internal control over financial reporting as of December 31, 2009, was audited by PricewaterhouseCoopers LLP, an independent accounting firm, as stated in its report which is included in the 2009 LG&E Annual Report.

Legal Proceedings

For a description of the significant legal proceedings, including, but not limited to, certain rates and regulatory, environmental, climate change and litigation matters, involving LG&E, reference is made to the information under the following captions of the Company's Annual Report for the year ended December 31, 2009: 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 Note 2, Rates and Regulatory Matters; Note 9, Commitments and Contingencies; and Note 12, Subsequent Events, of this quarterly report. Except as described in this quarterly report, to date, the proceedings reported in the Company's Annual Report for the year ended December 31, 2009, have not materially changed.

Other

In the normal course of business, other lawsuits, claims, environmental actions and other governmental proceedings arise against LG&E. To the extent that damages are assessed in any of these lawsuits, the Company 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 the Company's financial position or results of operations.

LOUISVILLE GAS & ELECTIRC COMPANY
FINANCIAL STATEMENTS

DECEMBER 31, 2010

Louisville Gas and Electric Company

Financial Statements and Additional Information

As of December 31, 2010 and 2009 and

for the years ended December 31, 2010, 2009 and 2008

Index of Abbreviations

AG	Attorney General of Kentucky
ARO	Asset Retirement Obligation
ASC	Accounting Standards Codification
BART	Best Available Retrofit Technology
CAIR	Clean Air Interstate Rule
CAMR	Clean Air Mercury Rule
CATR	Clean Air Transport 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	Louisville Gas and Electric Company
CT	Combustion Turbine
DSM	Demand Side Management
ECR	Environmental Cost Recovery
EKPC	East Kentucky Power Cooperative, Inc.
E.ON	E.ON AG
E.ON U.S.	E.ON U.S. LLC and Subsidiaries
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)
GAAP	U.S. Generally Accepted Accounting Principles
GHG	Greenhouse Gas
GSC	Gas Supply Clause
Gwh	Gigawatt hours or one thousand Mwh
IBEW	International Brotherhood of Electrical Workers
IMEA	Illinois Municipal Electric Agency
IMPA	Indiana Municipal Power Agency
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
LIBOR	London Interbank Offered Rate
LKE	LG&E and KU Energy LLC and Subsidiaries (formerly E.ON U.S. LLC and Subsidiaries)
Mcf	Thousand Cubic Feet
MMcf	Million Cubic Feet
MISO	Midwest Independent Transmission System Operator, Inc.

Index of Abbreviations

MMBtu	Million British thermal units
Moody's	Moody's Investor Services, Inc.
MVA	Megavolt-ampere
Mw	Megawatts
Mwh	Megawatt hours
NAAQS	National Ambient Air Quality Standards
NERC	North American Electric Reliability Corporation
NO_2	Nitrogen Dioxide
NOx	Nitrogen Oxide
OATT	Open Access Transmission Tariff
OVEC	Ohio Valley Electric Corporation
PBR	Performance Based Rates
PPL	PPL Corporation
Predecessor	The Company during the time period prior to November 1, 2010
PUHCA 2005	Public Utility Holding Company Act of 2005
RSG	Revenue Sufficiency Guarantee
S&P	Standard & Poor's Rating Service
SCR	Selective Catalytic Reduction
SERC	SERC Reliability Corporation
Servco	LG&E and KU Services Company (formerly E.ON U.S. Services Inc.)
SIP	State Implementation Plan
SO_2	Sulfur Dioxide
SPP	Southwest Power Pool, Inc.
Successor	The Company during the time period after October 31, 2010
TC1	Trimble County Unit 1
TC2	Trimble County Unit 2
TVA	Tennessee Valley Authority
Utilities	LG&E and KU
VDT	Value Delivery Team Process
Virginia Commission	Virginia State Corporation Commission
WNA	Weather Normalization Adjustment

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Forward-Looking Information

LG&E uses forward-looking statements in this annual report. Statements that are not historical facts are forward-looking statements, and are based on beliefs and assumptions of management, and on information currently available to management. Forward-looking statements include statements preceded by, followed by or using such words as "believe," "expect," "anticipate," "plan," "estimate" or similar expressions. Such statements speak only as of the date they are made, and the Company undertakes no obligation to update publicly any of them in light of new information or future events. Actual results may materially differ from those implied by forward-looking statements due to known and unknown risks and uncertainties. Factors that could cause actual results to differ materially from those indicated in any forward-looking statement include, but are not limited to:

- fuel supply availability;
- weather conditions affecting generation production, customer energy use and operating costs;
- operation, availability and operating costs of existing generation facilities;
- transmission and distribution system conditions and operating costs;
- collective labor bargaining negotiations;
- the outcome of litigation against the Company;
- potential effects of threatened or actual terrorism or war or other hostilities;
- commitments and liabilities;
- market demand and prices for energy, capacity, transmission services, emission allowances and delivered fuel;
- competition in retail and wholesale power and natural gas markets;
- liquidity of wholesale power markets;
- defaults by counterparties under the Company's energy, fuel or other power product contracts;
- market prices of commodity inputs for ongoing capital expenditures;
- capital market conditions, including the availability of capital or credit, changes in interest rates, and decisions regarding capital structure;
- the fair value of debt and equity securities and the impact on defined benefit costs and resultant cash funding requirements for defined benefit plans;
- interest rates and their effect on pension and retiree medical liabilities;
- volatility in or the impact of other changes in financial or commodity markets and economic conditions;
- profitability and liquidity, including access to capital markets and credit facilities;
- new accounting requirements or new interpretations or applications of existing requirements;
- securities and credit ratings;
- current and future environmental conditions and requirements and the related costs of compliance, including environmental capital expenditures, emission allowance costs and other expenses;
- political, regulatory or economic conditions in states, regions or countries where the Company conducts business;
- receipt of necessary governmental permits, approvals and rate relief;
- new state or federal legislation, including new tax, environmental, health care or pension-related legislation;
- state or federal regulatory developments;
- the impact of any state or federal investigations applicable to the Company and the energy industry;
- the effect of any business or industry restructuring;
- development of new projects, markets and technologies;

- performance of new ventures; and
- asset acquisitions and dispositions.

In light of these risks and uncertainties, the events described in the forward-looking statements might not occur or might occur to a different extent or at a different time than the Company has described. For additional details regarding these and other risks and uncertainties, see Risk Factors.

Business

General

LG&E, incorporated in Kentucky in 1913, is a regulated utility engaged in the generation, transmission, distribution and sale of electric energy and the storage, distribution and sale of natural gas. LG&E provides electric service to approximately 395,000 customers in Louisville and adjacent areas in Kentucky covering approximately 700 square miles in nine counties. Natural gas service is provided to approximately 320,000 customers in its electric service area and eight additional counties in Kentucky. Approximately 95% of the electricity generated by LG&E is produced by its coal-fired electric generating stations, all equipped with systems to reduce SO_2 emissions. The remainder is generated by natural gas and oil fueled CTs and a hydroelectric power plant. Underground natural gas storage fields help the Company provide economical and reliable natural gas service to customers.
On November 1, 2010, LG&E became an indirect wholly owned subsidiary of PPL, when PPL acquired all of the outstanding limited liability company interests in the Company's direct parent, LKE, from E.ON US Investments Corp. LKE, a Kentucky limited liability company, also owns the affiliate, KU, a regulated utility engaged in the generation, transmission, distribution and sale of electric energy in Kentucky, Virginia and Tennessee. Following the acquisition, the Company's business has not changed. LG&E and KU are continuing as subsidiaries of LKE, which is now an intermediary holding company in the PPL group of companies.

Headquartered in Allentown, Pennsylvania, PPL is an energy and utility holding company that was incorporated in 1994. Through its subsidiaries, PPL owns or controls about 19,000 megawatts of generating capacity in the U.S., sells energy in key U.S. markets and delivers electricity and natural gas to about 5.3 million customers in the U.S. and the U.K.

Predecessor and Successor

LG&E's historical financial results are presented using "Predecessor" or "Successor" to designate the periods before or after PPL's acquisition of LKE. Predecessor covers the time period prior to November 1, 2010. Successor covers the time period after October 31, 2010. Certain accounting and presentation methods were changed to acceptable alternatives to conform to PPL accounting policies and the cost basis of certain assets and liabilities were changed as of November 1, 2010, as a result of the application of push-down accounting. Consequently, the financial position, results of operations and cash flows for the Successor period are not comparable to the Predecessor period.

Despite the separate presentation, the core operations of the Company have not changed. See Note 1, Summary of Significant Accounting Policies, for the major differences in Predecessor and Successor accounting policies. See Note 2, Acquisition by PPL, for information regarding the acquisition and the purchase accounting adjustments.

Operations

Dollars are in millions unless otherwise noted.

For the year ended December 31, 2010, 77% of total operating revenues were derived from electric operations and 23% from natural gas operations. Electric and gas operating revenues and the percentages by class of service on a combined basis for this period were as follows:

	Successor November 1, 2010 through December 31, 2010		Predecessor January 1, 2010 through October 31, 2010			
	Electric	Gas	Electric	Gas	Combined	% Combined
Residential	$ 57	$ 56	$ 309	$ 137	$ 559	43%
Industrial and commercial	70	22	351	58	501	38%
Other retail	17	5	87	11	120	9%
Wholesale	25	2	99	5	131	10%
	$ 169	$ 85	$ 846	$ 211	$ 1,311	100%

The sources of electric operating revenues and volumes of sales for the following periods in 2010, 2009 and 2008 were as follows:

	Successor November 1, 2010 through December 31, 2010		Predecessor January 1, 2010 through October 31, 2010		Predecessor Year Ended December 31, 2009		Predecessor Year Ended December 31, 2008	
	Revenues	Volumes (Gwh)	Revenues	Volumes (Gwh)	Revenues	Volumes (Gwh)	Revenues	Volumes (Gwh)
Residential	$ 57	682	$ 309	3,910	$ 310	4,096	$ 301	4,206
Industrial and commercial	70	1,024	351	5,372	377	6,029	387	6,574
Other retail	17	209	87	1,141	89	1,280	82	1,303
Wholesale	25	1,107	99	4,138	142	5,711	246	7,884
	$ 169	3,022	$ 846	14,561	$ 918	17,116	$ 1,016	19,967

LG&E's all time peak electric load occurred in 2010 and was 2,852 Mw on August 4, 2010, when the temperature reached a high of 102 degrees Fahrenheit in Louisville.

The sources of natural gas operating revenues and the volumes of sales for the following periods in 2010, 2009 and 2008 were as follows:

	Successor		Predecessor					
	November 1, 2010 through December 31, 2010		January 1, 2010 through October 31, 2010		Year Ended December 31, 2009		Year Ended December 31, 2008	
	Revenues	Volumes (MMcf)	Revenues	Volumes (MMcf)	Revenues	Volumes (MMcf)	Revenues	Volumes (MMcf)
Residential	$ 56	6,583	$ 137	14,424	$ 230	19,742	$ 281	21,338
Industrial and commercial	22	2,903	58	7,319	98	9,600	136	10,914
Other retail	5	490	11	1,097	20	1,568	23	1,677
Wholesale	2	2,614	5	8,719	6	10,866	12	12,241
	$ 85	12,590	$ 211	31,559	$ 354	41,776	$ 452	46,170

Natural gas billings include a WNA mechanism which adjusts the distribution cost component of residential and commercial customers to normal temperatures during the heating season months of November through April, somewhat mitigating the effect of above- or below-normal weather on residential and commercial revenues. In July 2009, the Kentucky Commission approved LG&E's request to make the current WNA mechanism permanent.

During 2010, the maximum daily natural gas sendout was approximately 416,000 Mcf, occurring on December 13, 2010, when the average temperature for the day in Louisville was 15 degrees Fahrenheit. Supply on that day consisted of approximately 305,000 Mcf from pipeline deliveries, approximately 111,000 Mcf from on-system gas storage.

The Company's power generating system includes coal-fired steam generating stations, with natural gas and oil fueled CTs which supplement the system during peak or emergency periods. As of December 31, 2010, LG&E's system capacity was:

Fuel/Plant	Total Mw Summer Capacity (a)	% Ownership	Ownership or Lease Interest in Mw	Location
Coal (steam)				
Mill Creek	1,472	100.00	1,472	Jefferson County, KY
Cane Run	563	100.00	563	Jefferson County, KY
Trimble County (b)	511	75.00	383	Trimble County, KY
OVEC - Clifty Creek (c)	1,304	5.63	73	Jefferson County, IN
OVEC - Kyger Creek (c)	1,086	5.63	61	Gallia County, OH
Total steam	4,936		2,552	

Fuel/Plant	Total Mw Summer Capacity (a)	% Ownership	Ownership or Lease Interest in Mw	Location
Natural gas/oil (combustion turbines)				
Trimble County Units 7-10 (d)	640	37.00	237	Trimble County, KY
E.W. Brown Units 6-7 (d)	338	38.00	124	Mercer County, KY
Trimble County Units 5-6 (d)	320	29.00	93	Trimble County, KY
Paddy's Run Unit 13 (d)	158	53.00	84	Jefferson County, KY
E.W. Brown Unit 5	129	53.00	66	Mercer County, KY
Paddy's Run Units 11-12	35	100.00	35	Jefferson County, KY
Zorn	14	100.00	14	Jefferson County, KY
Cane Run	14	100.00	14	Jefferson County, KY
Total combustion turbines	1,648		667	
Hydro				
Ohio Falls Hydroelectric Station	52	100.00	52	Jefferson County, KY
Total hydro	52		52	
Total system capacity	6,636		3,271	

(a) The capacity of generation units is based on a number of factors, including the operating experience and physical conditions of the units and may be revised periodically to reflect changed circumstances.
(b) TC1 is jointly owned with IMEA and IMPA. See Note 14, Jointly Owned Electric Utility Plant, for further information.
(c) LG&E is contractually entitled to 5.63% of OVEC's output based on a power purchase agreement which is comprised of annual minimum debt service payments, as well as contractually-required reimbursement of plant operating, maintenance and other expenses. OVEC's capacity is shown at unit nameplate ratings.
(d) Units are jointly owned with KU. See Note 14, Jointly Owned Electric Utility Plant, for further information.

With limited exceptions the Company took care, custody and control of TC2 on January 22, 2011, and has dispatched the unit to meet customer demand since that date. LG&E and the contractor agreed to a further amendment of the construction agreement whereby the contractor will complete certain actions relating to identifying and completing any necessary modifications to allow operation of TC2 on all fuels in accordance with initial specifications prior to certain dates, and amending the provisions relating to liquidated damages. Unit 2 is coal-fired and has a capacity of 760 Mw, of which LG&E's share is 108 Mw.

On December 31, 2010, LG&E's electric transmission system included 45 substations (32 of which are shared with the distribution system) with transformer capacity of approximately 6,760 MVA and approximately 911 miles of lines. The electric distribution system included 95 substations (32 of which are shared with the transmission system) with transformer capacity of approximately 5,224 MVA and approximately 3,920 miles of overhead lines and 2,350 miles of underground conduit.

LG&E contracts with the TVA to act as LG&E's transmission reliability coordinator and SPP to function as LG&E's independent transmission operator, pursuant to FERC requirements. The TVA and SPP contracts provide services through August 31, 2011 and August 31, 2012, respectively. See Note 3, Rates and Regulatory Matters, for further information.

LG&E and KU jointly dispatch their generation units with the lowest cost generation used to serve their retail native load. When LG&E has excess generation capacity after serving its own retail native load and its generation cost is lower than that of KU, KU purchases electricity from LG&E. When KU has excess generation capacity after serving its own retail native load and its generation cost is lower than that of LG&E, LG&E purchases electricity from KU. These transactions are recorded as intercompany wholesale sales and purchases and are recorded by each company at a price equal to the seller's fuel cost. Savings realized from purchasing electricity intercompany instead of generating from their own higher costs units or purchasing from the market are shared equally between the Utilities. The volume of energy each company has to sell to the other is dependent on its native load needs and its available generation.

LG&E's natural gas transmission system includes 380 miles of transmission mains, consisting of 255 miles of natural gas transmission lines, 119 miles of natural gas storage lines and 6 miles of natural gas combustion turbine lines. LG&E's the natural gas distribution system includes 4,235 miles of distribution mains.

Five underground natural gas storage fields, with a current working natural gas capacity of approximately 15 million Mcf, help provide economical and reliable natural gas service to ultimate consumers. By using natural gas storage facilities, LG&E avoids the costs typically associated with more expensive pipeline transportation capacity to serve peak winter heating loads. Natural gas is stored in the summer season for withdrawal in the subsequent winter heating season. Without its storage capacity, LG&E would be required to buy additional natural gas and pipeline transportation services during the winter months when customer demand increases and when the prices for natural gas supply and transportation services are typically at their highest. Several suppliers under contracts of varying duration provide competitively priced natural gas. The underground storage facilities, in combination with its purchasing practices, enable the Company to offer natural gas sales service at competitive rates. At December 31, 2010, LG&E had a 12 million Mcf inventory balance of natural gas stored underground valued at $60 million.

A number of large commercial and industrial customers purchase their natural gas requirements directly from alternate suppliers for delivery through LG&E's distribution system. These large commercial and industrial customers account for approximately one-fourth of the Company's annual throughput.

The estimated maximum deliverability from storage during the early part of the heating season is expected to be in excess of 350,000 Mcf/day. Under mid-winter design conditions, LG&E expects to be able to withdraw about 307,000 Mcf/day from its storage facilities. The deliverability of natural gas from the storage facilities decreases as storage inventory levels are reduced by seasonal withdrawals.

Substantially all of LG&E's real and tangible property located in Kentucky is subject to a mortgage lien, securing its first mortgage bonds. See Note 11, Long-Term Debt, for further information.

Rates and Regulations

PPL, LG&E's ultimate parent, is a holding company under PUHCA 2005. PPL, its utility subsidiaries, including LG&E, 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. LG&E 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.

The Company is subject to the jurisdiction of the FERC and Kentucky Commission in virtually all matters related to electric and natural gas utility regulation, and as such, its accounting is subject to the regulated operations guidance of the FASB ASC. Given its competitive position in the marketplace and the status of regulation in Kentucky, there are no plans or intentions to discontinue the application of the regulated operations guidance of the FASB ASC.

On April 28, 2010, E.ON U.S. announced that a Purchase and Sale Agreement (the "Agreement") had been entered into among E.ON US Investments Corp., PPL and E.ON.

The transaction was subject to customary closing conditions, including the expiration or termination of the applicable waiting period under the Hart-Scott-Rodino Act, receipt of required regulatory approvals (including the FERC and state regulators in Kentucky) and the absence of injunctions or restraints imposed by governmental entities.

Change of control and financing-related applications were filed on May 28, 2010, with the Kentucky Commission. An application with the FERC was filed on June 28, 2010. During the second quarter of 2010, a number of parties were granted intervenor status in the Kentucky Commission proceedings and data request filings and responses occurred. Early termination of the Hart-Scott-Rodino waiting period was received on August 2, 2010.

A hearing in the Kentucky Commission proceedings was held on September 8, 2010, at which time a unanimous settlement agreement was presented. In the settlement, LG&E committed that no base rate increases would take effect before January 1, 2013. The LG&E rate increases that took effect on August 1, 2010, were not impacted by the settlement. Under the terms of the settlement, LG&E retains the right to seek approval for the deferral of "extraordinary and uncontrollable costs." Interim rate adjustments will continue to be permissible during that period for existing fuel, environmental and demand-side management cost trackers. The agreement also substitutes an acquisition savings shared deferral mechanism for the requirement that the Company file a synergies plan with the Kentucky Commission. This mechanism, which will be in place until the earlier of five years or the first day of the year in which a base rate increase becomes effective, permits LG&E to earn up to a 10.75% return on equity. Any earnings above a 10.75% return on equity will be shared with customers on a 50%/50% basis. On September 30, 2010, the Kentucky Commission issued an Order approving the transfer of ownership of LG&E via the acquisition of E.ON U.S. by PPL, incorporating the terms of the submitted settlement. The Commission's Orders contained a number of other commitments with regard to operations, workforce, community involvement and other matters.

In mid-September 2010, LG&E and other applicants in the FERC change of control proceeding reached an agreement with the protesters, whereby such protests have been withdrawn. The agreement, which was filed for consideration with the FERC, includes various conditional commitments, such as a continuation of certain existing undertakings with protesters in prior cases, an exclusion of any transaction-related costs from wholesale energy and tariff customer rates to the extent that LG&E agreed not to seek the same transaction-related cost from retail customers and agreements to coordinate with protesters in certain open or ongoing matters. A FERC Order approving the transaction was received on October 26, 2010, and the transaction was completed on November 1, 2010.

In January 2010, LG&E filed an application with the Kentucky Commission requesting increases in electric base rates of approximately 12%, or $95 million annually and natural gas base rates of approximately 8%, or $23 million annually. In June 2010, LG&E and all of the intervenors, except the AG, agreed to a stipulation providing for increases in electric base rates of $74 million annually and natural gas base rates of $17 million annually and filed a request with the Kentucky Commission to approve such settlement. An Order in the proceeding was issued in July 2010, approving all the provisions in the stipulation including a return on equity range of 9.75-10.75%. The new rates became effective on August 1, 2010.

In January 2009, a significant ice storm passed through LG&E's service area causing approximately 205,000 customer outages, followed closely by a severe wind storm in February 2009 causing approximately 37,000 customer outages. The Company filed an application with the Kentucky Commission in April 2009, requesting approval to establish a regulatory asset and defer for future recovery approximately $45 million in incremental operation and maintenance expenses related to the storm restoration. In September 2009, the Kentucky Commission issued an Order allowing the Company to establish a regulatory asset of up to $45 million based on its actual costs for storm damages and service restoration due to the January and February 2009 storms. In September 2009, the Company established a regulatory asset of $44 million for actual costs incurred. LG&E received approval in its 2010 base rate case to recover this asset over a ten year period with recovery beginning August 1, 2010.

In September 2008, high winds from the remnants of Hurricane Ike passed through the service area causing significant outages and system damage. In October 2008, LG&E filed an application with the Kentucky Commission requesting approval to establish a regulatory asset and defer for future recovery approximately $24 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 $24 million based on its actual costs for storm damages and service restoration due to Hurricane Ike. In December 2008, the Company established a regulatory asset of $24 million for actual costs incurred. The Company received approval in its 2010 base rate cases to recover this asset over a ten year period beginning August 1, 2010.

In July 2008, LG&E filed an application with the Kentucky Commission requesting increases in electric and natural gas base rates. In January 2009, LG&E, the AG, the KIUC and all other parties to the rate case filed a settlement agreement with the Kentucky Commission, under which LG&E's natural gas base rates increased by $22 million annually and its electric base rates decreased by $13 million annually. An Order approving the settlement agreement was received in February 2009. The new rates were implemented effective February 6, 2009.

For a further discussion of regulatory matters, see Note 3, Rates and Regulatory Matters.

Coal Supply

Coal-fired generating units provided approximately 95% of LG&E's net kWh generation for 2010. The remainder is generated by natural gas and oil fueled CTs and a hydroelectric power plant. Coal is expected to be the predominant fuel used by LG&E in the foreseeable future, with natural gas and oil being used for peaking capacity and flame stabilization in coal-fired boilers or in emergencies. The Company has no nuclear generating units and has no plans to build any in the foreseeable future.

Fuel inventory is maintained at levels estimated to be necessary to avoid operational disruptions at the coal-fired generating units. Reliability of coal deliveries can be affected periodically by a number of factors, including fluctuations in demand, coal mine production issues and other supplier or transporter operating difficulties.

LG&E has entered into coal supply agreements with various suppliers for coal deliveries for 2011 and beyond and normally augments its coal supply agreements with spot market purchases. The Company has a coal inventory policy which it believes provides adequate protection under most contingencies.

LG&E expects to continue purchasing most of its coal, which has sulfur content in the 2.0% - 3.5% range, from western Kentucky, southern Indiana, southern Illinois, Ohio, Wyoming and West Virginia for the foreseeable future. This supply, in combination with the Company's SO_2 removal systems, is expected to enable LG&E to continue to provide electric service in compliance with existing environmental laws and regulations. Coal is delivered to LG&E's generating stations by a mix of transportation modes, including rail and barge.

Natural Gas Supply

LG&E purchases natural gas supplies from multiple sources under contracts for varying periods of time, while transportation services are purchased from Texas Gas Transmission LLC ("Texas Gas") and Tennessee Gas Pipeline Company ("Tennessee Gas").

LG&E currently transports natural gas on the Texas Gas system under Rate Schedules No-Notice Service ("NNS"), Firm Transport ("FT") and Short-Term Firm ("STF"). LG&E's total winter season NNS capacity is 184,900 MMBtu/day and its total summer season NNS capacity is 60,000 MMBtu/day. The three separate NNS agreements, which provide for equal amounts of capacity, are subject to termination by LG&E during 2015, 2016 and 2018. LG&E's FT capacity is 10,000 MMBtu/day throughout the year (winter and summer seasons). The FT agreement is subject to termination by LG&E during 2016. LG&E's winter season STF capacity is 100 MMBtu/day and its summer season capacity is 18,000 MMBtu/day. The STF agreement is subject to termination by LG&E during 2013. LG&E also transports on the Tennessee Gas system under Rate Schedule Firm Transport-A ("FT-A"). LG&E's FT-A capacity is 51,000 MMBtu/day throughout the year (winter and summer seasons). The FT-A agreement with Tennessee Gas expires during 2012.

LG&E participates in rate and other proceedings affecting the regulated interstate natural gas pipelines that provide it service. Both Texas Gas and Tennessee Gas have active proceedings at the FERC in which LG&E is participating. Although neither pipeline is currently billing charges subject to refund, Tennessee Gas has filed at the FERC for an increase in base rates as well as other charges with an anticipated effective date of June 1, 2011. However, LG&E's current negotiated rate in its transportation agreement with Tennessee Gas insulates it from the potential impact of increases in base rates as proposed by Tennessee Gas for the duration of that agreement.

LG&E also has a portfolio of supply arrangements of various terms with a number of suppliers designed to meet its firm sales obligations. These natural gas supply arrangements include pricing provisions that are market-responsive. In tandem with pipeline transportation services, these natural gas supplies provide the reliability and flexibility necessary to serve LG&E's natural gas customers.

Seasonality

Demand for and market prices for electricity and natural gas are affected by weather. As a result, LG&E's overall operating results in the future may fluctuate substantially on a seasonal basis, especially when more severe weather conditions such as heat waves or winter storms make such fluctuations more pronounced. The pattern of this fluctuation may change depending on the type and location of the facilities LG&E owns and the terms of its contracts to purchase or sell electricity and natural gas.

Environmental Matters

General

Protection of the environment is a major priority for LG&E and a significant element of its business activities. LG&E's properties and operations are subject to extensive environmental-related oversight by federal, state and local regulatory agencies, including via air quality, water quality, waste management and similar laws and regulations. Therefore, LG&E must conduct its operations in accordance with numerous permit and other requirements issued under or contained in such laws or regulations.

Climate Change

Recent developments continue to indicate an increased possibility of significant climate change or GHG legislation or regulation, at the international, federal, regional and state levels. During December 2009, as part of the United Nation's Copenhagen Accord, the United States agreed to a non-binding goal to reduce GHG emissions to 17% below 2005 levels by 2020. Additionally, during 2009, the U.S. House of Representatives passed comprehensive GHG legislation, which included a number of measures to limit GHG emissions and achieve GHG emission reduction targets below 2005 levels of 3% by 2012, 17% by 2020 and 83% by 2050. Similar legislation has been considered in the U.S. Senate, but the prospects for passage remain uncertain. In late 2009, the EPA issued a final endangerment finding relating to mobile sources of GHGs and a GHG reporting requirement beginning in 2010. In 2010, the EPA issued a final rule requiring implementation of best available control technology for GHG emissions from new or modified power plants, effective January 2011. In December 2010, the EPA announced that it intends to propose New Source Performance Standards addressing GHG emissions from new and existing power plants, with a proposed rule expected in July 2011. Finally, a number of U.S. states, although not currently including Kentucky, have adopted GHG-reduction legislation or regulation of various sorts. The developing GHG initiatives include a number of differing structures and formats, including direct limitations on GHG sources, issuance of allowances for GHG emissions, cap-and-trade programs for such allowances, renewable or alternative generation portfolio standards, and mechanisms relating to demand reduction, energy efficiency, smart-grid, transmission expansion, carbon-sequestration or other

GHG-reducing efforts. While the final terms and impacts of such initiatives cannot be estimated, LG&E, as a primarily coal-fired utility, could be highly affected by such proceedings.

Among other emissions, GHGs include carbon-dioxide, which is produced via the combustion of fossil fuels such as coal and natural gas. LG&E's generating fleet is approximately 78% coal-fired, 20% oil/natural gas-fired and 2% hydroelectric based on capacity. During 2010, LG&E produced approximately 95% of its electricity from coal, 4% from natural gas combustion and 1% from hydroelectric generation, based on Mwh. During 2010, LG&E's emissions of GHGs were approximately16.2 million metric tons of carbon-dioxide equivalents from LG&E's owned or controlled generation sources. While its generation activities account for the bulk of its GHG emissions, other GHG sources at LG&E include operation of motor vehicles and powered equipment, leakage or evaporation associated with natural gas pipelines, refrigerating equipment and similar activities.

Ultimately, environmental matters or potential environmental matters can represent an important element of current or future potential capital requirements, future unit retirement or replacement decisions, supply and demand for electricity, operating and maintenance expenses or compliance risks for the Company. Based on prior regulatory precedent, LG&E currently anticipates that many of such direct costs may be recoverable through rates or other regulatory mechanisms, particularly with respect to coal-related generation, but the availability, timing or completeness of such rate recovery cannot be assured. Ultimately, climate change and other environmental matters will likely increase the level of capital expenditures and operating and maintenance costs incurred by the Company during the next several years. With respect to NAAQS, CATR, CAMR replacement and coal combustion byproducts developments, based on a preliminary analysis of proposed regulations, the Company may be required to consider actions such as upgrading existing emissions controls, installing additional emissions controls, upgrading byproducts disposal and storage and possible early replacement of coal-fired units. In order to comply with the coal combustion residual rules and the above referenced air rules, capital expenditures for LG&E are preliminarily estimated to be in the $1.5 to $1.8 billion range over the next 10 years, although final costs may substantially vary. This estimate does not include compliance with GHG rules or contemplated water-related environmental changes. See Risk Factors, Management's Discussion and Analysis and Note 13, Commitments and Contingencies, for further information.

State Executive or Legislative Matters

In November 2008, the Commonwealth of Kentucky issued an action plan to create efficient, sustainable energy solutions and strategies and move toward state energy independence. The plan outlines the following seven strategies to work toward these goals:

- Improve the energy efficiency of Kentucky's homes, buildings, industries and transportation fleet
- Increase Kentucky's use of renewable energy
- Sustainably grow Kentucky's production of biofuels
- Develop a coal-to-liquids industry in Kentucky to replace petroleum-based liquids
- Implement a major and comprehensive effort to increase natural gas supplies, including coal-to-natural gas in Kentucky
- Initiate aggressive carbon capture/sequestration projects for coal-generated electricity in Kentucky
- Examine the use of nuclear power for electricity generation in Kentucky

In December 2009, the Governor of Kentucky's Executive Task Force on Biomass and Biofuels issued a final report to establish potential strategic actions to develop biomass and biofuels industries in Kentucky. The plan noted the potential importance of biomass as a renewable energy source available to Kentucky and discussed various goals or mechanisms, such as the use of approximately 25 million tons of biomass for generation fuel annually, allotment of electricity and natural gas taxes and state tax credits to support biomass development.

In January 2010, a state-established Kentucky Climate Action Plan Council (the "Council") commenced formal activities. The Council, which includes governmental, industry, consumer and other representatives, seeks to identify possible Kentucky responses to potential climate change and federal legislation, including increasing statewide energy efficiency, energy independence and economic growth. The Council has established various technical work groups, including in the areas of energy supply and energy efficiency/conservation, to provide input, data and recommendations.

During the current session of the Kentucky General Assembly, as during prior legislative sessions, legislators have introduced or are expected to introduce various bills with respect to environmental or utility matters, including potential requirements relating to renewable energy portfolios, energy conservation measures, coal mining or coal byproduct operations and other matters. The current session is scheduled to end in March 2011 and until such time the prospects and final terms of any such legislation cannot be determined. Legislative and regulatory actions as a result of these proposals and their impact on LG&E, which may be significant, cannot currently be predicted.

Franchises and Licenses

LG&E provides electric delivery service and natural gas distribution services in its various service areas pursuant to certain franchises, licenses, statutory service areas, easements and other rights or permissions granted by state legislatures, cities or municipalities or other entities.

Competition

There are currently no other electric utilities operating within the electric service areas of LG&E. 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 any legislative or regulatory actions regarding industry restructuring and their impact on LG&E, which may be significant, cannot currently be predicted. See Note 3, Rates and Regulatory Matters, for further information.

Alternative energy sources such as electricity, oil, propane and other fuels provide indirect competition for natural gas revenues. Marketers may also compete to sell natural gas to certain large end-users. Approximately 25% of LG&E's annual throughput is purchased by large commercial and industrial customers directly from alternate suppliers for delivery through LG&E's distribution system. LG&E does not profit from its sale of natural gas as a commodity; therefore, customer natural gas purchases from alternative suppliers do not impact profitability. In addition, some large industrial and commercial customers may be able to physically bypass LG&E's facilities and seek delivery service directly from interstate pipelines or other natural gas distribution systems.

In April 2010, the Kentucky Commission commenced a proceeding to investigate natural gas retail competition programs, their regulatory, financial and operational aspects and potential benefits, if any, of such programs to Kentucky consumers. A number of entities, including LG&E, were parties to the proceeding. In December 2010, the Kentucky Commission issued an Order in the proceeding declining to endorse natural gas competition at the retail level, noting the existence of a number of transition or oversight costs and an uncertain level of economic benefits in such programs. With respect to existing natural gas transportation programs available to large commercial or industrial users, the Order indicates that the Kentucky Commission will review the utilities' current tariff structures, user thresholds and other terms and conditions of such programs, as part of such utilities' next regular natural gas rate cases.

Employees and Labor Relations

LG&E had 1,022 employees at December 31, 2010, consisting of 1,018 full-time employees and 4 part-time employees. Of the total employees, 686, or 67%, were operating, maintenance and construction employees represented by the IBEW Local 2100. In November 2008, the Company and its employees represented by the IBEW Local 2100 entered into a three-year collective bargaining agreement that provides for negotiated increases or changes to wages, benefits or other provisions.

Officers of the Company

Officers are elected annually by the Board of Directors. There are no family relationships among any of the executive officers, nor is there any arrangement or understanding between any executive officer and any other person pursuant to which the officer was selected.

Except as may be set forth in Legal Proceedings, there have been no events under any bankruptcy act, no criminal proceedings and no judgments or injunctions material to the evaluation of the ability and integrity of any executive officer during the past five years.

Listed below are the executive officers at December 31, 2010.

Name	Age	Positions Held During the Past Five Years	Dates
Victor A. Staffieri	55	Chairman of the Board, President and Chief Executive Officer	May 2001 – present
John R. McCall	67	Executive Vice President, General Counsel, Corporate Secretary and Chief Compliance Officer	July 1994 – present
Chris Hermann	63	Senior Vice President – Energy Delivery	February 2003 – present
Paula H. Pottinger	53	Senior Vice President – Human Resources	January 2006 – present
S. Bradford Rives	52	Chief Financial Officer	September 2003 – present
Paul W. Thompson	53	Senior Vice President – Energy Services	June 2000 – present

Officers generally serve in the same capacities at the Company, LKE and KU.

Risk Factors

Any of the events or circumstances described as risks below could result in a significant or material adverse effect on the business, results of operations, cash flows or financial condition. The risks and uncertainties described below may not be the only risks and uncertainties that LG&E faces. Additional risks and uncertainties not currently known or that LG&E currently deems immaterial may also result in a significant or material adverse effect on the business, results of operations, cash flow or financial condition.

LG&E's business is subject to significant and complex governmental regulation.

Various federal and state entities, including but not limited to the FERC and Kentucky Commission, regulate many aspects of utility operations of LG&E, including the following:

- the rates that LG&E may charge and the terms and conditions of the Company's service and operations;
- financial and capital structure matters;
- siting and construction of facilities;
- mandatory reliability and safety standards, and other standards of conduct;
- accounting, depreciation, and cost allocation methodologies;
- tax matters;
- affiliate restrictions;
- acquisition and disposal of utility assets and securities; and
- various other matters.

Such regulations or changes thereto may subject LG&E 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 rate requests and ultimately reduce, alter or limit the rates the Company seeks.

The profitability of LG&E is highly dependent on its ability to recover the costs of providing energy and utility services to its customers and earn an adequate return on its capital investments. LG&E currently provides services to retail customers at rates approved by one or more federal or state regulatory commissions, including those commissions referred to above. While these rates are generally regulated based on an analysis of their costs incurred in a base year, the rates LG&E is allowed to charge may or may not match its costs at any given time. While rate regulation is premised on providing a reasonable opportunity to earn a reasonable rate of return on invested capital, there can be no assurance that the applicable regulatory commissions will consider all of the costs to have been prudently incurred or that the regulatory process in which rates are determined will always result in rates that will produce full recovery of LG&E's costs or an adequate return on LG&E's capital investments. If the Company's costs are not adequately recovered through rates, it could have an adverse affect on the business, results of operations, cash flows or financial condition.

As part of the PPL acquisition commitments, LG&E has agreed, subject to certain limited exceptions such as fuel and environmental cost recoveries, that no base rate increase would take effect for Kentucky retail customers before January 1, 2013.

Transmission and interstate market activities of LG&E, as well as other aspects of the business, are subject to significant FERC regulation.

LG&E is subject to extensive regulation by the FERC covering matters including rates charged to transmission users, market-based or cost-based rates applicable to 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, including but not limited to the areas of market-based tariff authority, RSG resettlements in the MISO market, mandatory reliability standards and natural gas transportation regulation can affect the earnings, operations or other activities of LG&E.

Changes in transmission and wholesale power market structures could increase costs or reduce revenues.

Wholesale sales fluctuate with regional demand, fuel prices and contracted capacity. Changes to transmission and wholesale power market structures and prices may occur in the future, are not estimable and may result in unforeseen effects on energy purchases and sales, transmission and related costs or revenues. These can include commercial or regulatory changes affecting power pools, exchanges or markets in which LG&E participates.

LG&E undertakes significant capital projects and these activities are subject to unforeseen costs, delays or failures, as well as risk of inadequate recovery of resulting costs.

LG&E's business is capital intensive and requires significant investments in energy generation and distribution and other infrastructure projects, such as projects for environmental compliance. The completion of these projects without delays or cost overruns is subject to risks in many areas, including the following:

- approval, licensing and permitting;
- land acquisition and the availability of suitable land;
- skilled labor or equipment shortages;
- construction problems or delays, including disputes with third party intervenors;
- increases in commodity prices or labor rates;
- contractor performance;
- environmental considerations and regulations;
- weather and geological issues; and
- political, labor and regulatory developments.

Failure to complete capital projects on schedule or on budget, or at all, could adversely affect the Company's financial performance, operations and future growth.

The costs of compliance with, and liabilities under, environmental laws are significant and are subject to continual changes.

Extensive federal, state and local environmental laws and regulations are applicable to LG&E'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 but could be material. In addition, LG&E's costs may increase significantly if the requirements or scope of environmental laws or regulations, or similar rules, are expanded or changed from prior versions by the relevant agencies. Costs may take the form of increased capital or operating and maintenance expenses; monetary fines, penalties or forfeitures or other restrictions. Many of these environmental law considerations are also applicable to the operations of key suppliers, or customers, such as coal producers, industrial power users, etc., and may impact the costs of their products or their demand for LG&E's services.

LG&E is subject to operational and financial risks regarding certain on-going developments concerning environmental regulation.

A number of regulatory initiatives have been implemented or are under development which could have the effect of significantly increasing the environmental regulation or operational or compliance costs related to a number of emissions or operating activities which are associated with the combustion of coal as occurs at the Company's generating stations. Such developments could include potential new or revised federal or state legislation or regulation regarding emissions of NOx, SO_2, mercury and other particulates generally and regarding storage of coal combustion byproducts. Additional regulatory initiatives may occur in other areas involving the Company's operations, including revision of limitations on water discharge or intake activities or increased standards relating to polychlorinated biphenyl usage. Compliance with any new laws or regulations in these matters could result in significant changes to LG&E's operations, significant capital expenditures by the Company or significant increases in the cost of conducting business.

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 other factors can significantly affect the finances or operations of LG&E by changing demand levels; causing outages; damaging infrastructure or requiring significant repair costs; affecting capital markets and general economic conditions or impacting future growth.

LG&E is subject to operational and financial risks regarding potential developments concerning global climate change.

Various regulatory and industry initiatives have been implemented or are under development to regulate or otherwise reduce emissions of GHGs, which are emitted from the combustion of fossil fuels such as coal and natural gas, as occurs at the Company's generating stations. Such developments could include potential federal or state legislation or industry initiatives allocating or limiting GHG emissions; establishing costs or charges on GHG emissions or on fuels relating to such emissions; requiring GHG capture and sequestration; establishing renewable portfolio standards or generation fleet-diversification requirements to address GHG emissions; promoting energy efficiency and conservation; changes in transmission grid construction, operation or pricing to accommodate GHG-related initiatives; or other measures. The generation fleet of LG&E is predominantly coal-fired and may be highly impacted by developments in this area. Compliance with any new laws or regulations regarding the reduction of GHG emissions could result in significant changes to LG&E's operations, significant capital expenditures by the Company and a significant increase in the cost of conducting business. LG&E may face strong competition for, or difficulty in obtaining, required GHG-compliance related goods and services, including construction services, emissions allowances and financing, insurance and other inputs relating thereto. Increases in LG&E's costs or prices of producing or selling electric power due to GHG-related developments could materially reduce or otherwise affect the demand, revenue or margin levels applicable to its power, thus adversely affecting its financial condition or results of operations.

LG&E is subject to physical, market and economic risks relating to potential effects of climate change.

Climate change may produce changes in weather or other environmental conditions, including temperature or precipitation changes, such as warming or drought. These changes may affect farm and agriculturally-dependent businesses and activities, which are an important part of Kentucky's economy, and thus may impact consumer demand for electric power. Temperature increases could result in increased overall electricity volumes or peaks and precipitation changes could result in altered availability of water for plant cooling operations. These or other meteorological changes could lead to increased operating costs, capital expenses or power purchase costs by LG&E. Conversely, climate change could have a number of potential impacts tending to reduce demand. Changes may entail more frequent or more intense storm activity, which, if severe, could temporarily disrupt regional economic conditions and adversely affect electricity demand levels. As discussed in other risk factors, storm outages and damage often directly decrease revenues or increase expenses, due to reduced usage and higher restoration charges, respectively. GHG regulation could increase the cost of electric power, particularly power generated by fossil fuels, and such increases could have a depressive effect on the regional economy. Reduced economic and consumer activity in the service area of LG&E, both in general and specific to certain industries and consumers accustomed to previously low-cost power, could reduce demand for LG&E's electricity. Also, demand for services could be similarly lowered should consumers' preferences or market factors move toward favoring energy efficiency, low-carbon power sources or reduced electric usage generally.

The business of LG&E is subject to risks associated with local, national and worldwide economic conditions.

The consequences of prolonged recessionary conditions may include a lower level of economic activity and uncertainty or volatility regarding energy prices and the capital and commodity markets. A lower level of economic activity might result in a decline in energy consumption, unfavorable changes in energy and commodity prices and slower customer growth, which may adversely affect LG&E's future revenues and growth. Instability in the financial markets, as a result of recession or otherwise, also may affect the cost of capital and the ability to raise capital. A deterioration of economic conditions may lead to decreased production by LG&E's industrial customers and, therefore, lower consumption of electricity. Decreased economic activity may also lead to fewer commercial and industrial customers and increased unemployment, which may in turn impact residential customers' ability to pay. Further, worldwide economic activity has an impact on the demand for basic commodities needed for utility infrastructure. Changes in global demand may impact the ability to acquire sufficient supplies and the cost of those commodities may be higher than expected.

LG&E's business is concentrated in the Midwest United States, specifically Kentucky.

LG&E's business is concentrated in Kentucky. Local and regional economic conditions, such as population growth, industrial growth, expansion and economic development or employment levels, as well as the operational or financial performance of major industries or customers, can affect the demand for energy and LG&E's results of operations. Significant industries and activities in the service area of LG&E include airport and logistics activities; automotive; chemical and rubber processing; educational institutions; health care facilities; metal fabrication; and water and sewer utilities. Any significant downturn in these industries or activities or in local and regional economic conditions in LG&E's service area may adversely affect the demand for electricity in the service area.

LG&E is subject to operational risks relating to LG&E's generating plants, transmission facilities, distribution equipment, information technology systems and other assets and activities.

Operation of power plants, transmission and distribution facilities, information technology systems and other assets and activities subjects LG&E to many risks, including the breakdown or failure of equipment; accidents; security breaches, viruses or outages affecting information technology systems; labor disputes; obsolescence; delivery/transportation problems and disruptions of fuel supply and performance below expected levels. Occurrences of these events may impact the ability of LG&E to conduct its business efficiently or lead to increased costs, expenses or losses.

Although LG&E maintains customary insurance coverage for certain of these risks common to utilities, it does not have insurance covering the transmission and distribution systems, other than substations, because it has found the cost of such insurance to be prohibitive. If LG&E is unable to recover the costs incurred in restoring transmission and distribution properties following damage resulting from ice storms, tornados or other natural disasters or to recover the costs of other liabilities arising from the risks of its business, through a change in rates or otherwise, or if such recovery is not received on a timely basis, it may not be able to restore losses or damages to its properties without an adverse effect on its financial condition, results of operations or its reputation.

LG&E is subject to liability risks relating to its generation, transmission, distribution and retail businesses.

The conduct of the physical and commercial operations of LG&E subjects it to many risks, including risks of potential physical injury, property damage or other financial affects, caused to or caused by employees, customers, contractors, vendors, contractual or financial counterparties and other third parties.

LG&E could be negatively affected by rising interest rates, downgrades to bond credit ratings or other negative developments in its ability to access capital markets.

In the ordinary course of business, LG&E is reliant upon adequate long-term and short-term financing means to fund significant capital expenditures, debt interest or maturities and operating needs. As a capital-intensive business, the Company is sensitive to developments in interest rate levels; credit rating considerations; insurance, security or collateral requirements; market liquidity and credit availability and refinancing steps necessary or advisable to respond to credit market changes. Changes in these conditions could result in increased costs and decreased liquidity available to the Company.

LG&E 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 the Company.

LG&E is subject to risks associated with defined benefit retirement plans, health care plans, wages and other employee-related matters.

LG&E sponsors pension and postretirement benefit plans for its employees. Risks with respect to these plans include adverse developments in legislation or regulation, future costs or funding levels, returns on investments, market fluctuations, interest rates and actuarial matters. Changes in health care rules, market practices or cost structures can affect current or future funding requirements or liabilities. Without sustained growth in respective investments over time to increase the value of plan assets, LG&E could be required to fund plans with significant amounts of cash. LG&E is also subject to risks related to 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.

LG&E is subject to risks associated with federal and state tax regulations.

Changes in taxation as well as the inherent difficulty in quantifying potential tax effects of business decisions could negatively impact results of operations. LG&E is required to make judgments in order to estimate its obligations to taxing authorities. These tax obligations include income, property, sales and use and employment-related taxes. LG&E also estimates its ability to utilize tax benefits and tax credits. Due to the revenue needs of the state and jurisdictions in which LG&E operates, various tax and fee increases may be proposed or considered. LG&E cannot predict whether legislation or regulation will be introduced or the effect on the Company of any such changes. If enacted, any changes could increase tax expense and could have a negative impact on its results of operations and cash flows.

Legal Proceedings

Rates and Regulatory Matters

For a discussion of current rates and regulatory matters, including recent electric and natural gas base rate increase proceedings, rate commitments in change-of-control proceedings, TC2 proceedings, FERC and Kentucky Commission proceedings and other rates or regulatory matters affecting LG&E, see Note 3, Rates and Regulatory Matters, and Note 13, Commitments and Contingencies.

Environmental

For a discussion of environmental matters, including potential coal combustion byproduct or ash pond regulation; additional reductions in SO_2, NOx and other regulated emissions; other emissions proceedings; manufactured gas plant sites; environmental permit challenges; and other environmental items affecting LG&E, see Risk Factors, Note 3, Rates and Regulatory Matters, and Note 13, Commitments and Contingencies.

Climate Change

For a discussion of matters relating to potential climate change, GHG emission or global warming developments, including increased legislative and regulatory activity which could limit or increase costs applicable to fossil fuel generation sources, legal proceedings claiming damages relating to global warming, GHG reporting requirements and other matters, see Business, Risk Factors, Management's Discussion and Analysis and Note 13, Commitments and Contingencies.

Litigation

In connection with an administrative proceeding alleging a violation by a former Argentine affiliate under that country's 2002-2003 emergency currency exchange laws, claims are pending against the affiliate's then directors, including two individuals who are executive officers of the Company, in a specialized Argentine financial criminal court. Under applicable Argentine laws, directors of a local company may be liable for monetary penalties for a subject company's violations of the currency laws. The affiliate and the relevant executive officers believe their actions were in compliance with the relevant laws and have presented defenses in the administrative and criminal proceedings. LKE has standard indemnification arrangements with its executive officers. The former affiliate is now owned by a third party, which has agreed to indemnify LKE and the relevant executive officers.

For a discussion of litigation matters, see Note 13, Commitments and Contingencies.

Other

In the normal course of business, other lawsuits, claims, environmental actions and other governmental proceedings arise against LG&E. To the extent that damages are assessed in any of these lawsuits, the Company 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 LG&E's financial position or results of operations.

Selected Financial Data

Dollars are in millions unless otherwise noted.

	Successor	Predecessor				
	November 1, 2010 through December 31, 2010	January 1, 2010 through October 31, 2010	Year Ended December 31,			
			2009	2008	2007	2006
Operating revenues	$ 254	$ 1,057	$ 1,272	$ 1,468	$ 1,285	$ 1,338
Operating income	$ 40	$ 188	$ 167	$ 219	$ 229	$ 223
Net income	$ 19	$ 109	$ 95	$ 90	$ 120	$ 117
Total assets	$ 4,519	$ 3,699	$ 3,568	$ 3,653	$ 3,313	$ 3,184
Long-term debt obligations (including amounts due within one year)	$ 1,112	$ 896	$ 896	$ 896	$ 984	$ 820

Management's Discussion and Analysis and Notes to Financial Statements should be read in conjunction with the above information.

Management's Discussion and Analysis

Management's Discussion and Analysis should be read in conjunction with the Financial Statements and Notes for the years ended December 31, 2010, 2009 and 2008. Dollars are in millions unless otherwise noted.

The purpose of "Management's Discussion and Analysis" is to provide information about LG&E's performance in implementing its' strategies and managing risks and challenges. Specifically:

- "Overview" provides background regarding LG&E's business and identifies significant matters with which management is primarily concerned in evaluation of LG&E's financial condition and operating results.
- "Results of Operations" provides a description of LG&E's operating results in 2010, 2009 and 2008, including a review of earnings and a brief outlook for 2011.
- "Financial Condition" provides an analysis of LG&E's liquidity position and credit profile, including its sources of cash (including bank credit facilities and sources of operating cash flow) and uses of cash (including contractual obligations and capital expenditure requirements) and the key risks and uncertainties that impact LG&E's past and future liquidity position and financial condition. This subsection also includes a discussion of LG&E's current credit ratings.
- "Application of Critical Accounting Policies and Estimates" provides an overview of the accounting policies that are particularly important to the results of operations and financial condition of LG&E and that require its management to make significant estimates, assumptions and other judgments.

Overview

LG&E is a regulated utility engaged in the generation, transmission, distribution and sale of electric energy and the storage, distribution and sale of natural gas in Kentucky. See the Business section for a description of the business. The rates LG&E charges its customers requires approval of the appropriate regulatory government agency. See Note 3, Rates and Regulatory Matters, for information regarding rate cases, regulatory assets and liabilities and other regulatory matters.

LG&E and its affiliate, KU, are wholly owned subsidiaries of LKE, a Kentucky limited liability company. PPL acquired LKE on November 1, 2010. Headquartered in Allentown, Pennsylvania, PPL is an energy and utility holding company that was incorporated in 1994. Through its subsidiaries, PPL owns or controls about 19,000 megawatts of generating capacity in the U.S., sells energy in key U.S. markets and delivers electricity and natural gas to about 5.3 million customers in the U.S. and the U.K. Following the acquisition, both LG&E and KU continue operating as subsidiaries of LKE, which is now an intermediary holding company in the PPL group of companies. See Note 2, Acquisition by PPL, for further information regarding the acquisition.

In operating its business, the Company faces several risks including credit risks, liquidity risks, interest rate risks and commodity and price risks. For instance, the Company has credit risks from counterparties, customers and effects of its own credit ratings. LG&E attempts to manage these risks through the adoption of financial and operational risk management programs that, among other things, are designed to monitor and reduce its exposure to these risks. Identified within "Management's Discussion and

Analysis" of "Financial Condition" and "Results of Operations" are risks LG&E's management currently consider material; these risks are not the only risks faced by LG&E. Additional risks not presently known or currently deemed immaterial may also impair LG&E's business operations. See Risk Factors and Financial Condition - Risk Management for further discussion.

Predecessor and Successor Financial Presentation

LG&E's financial statements and related financial and operating data include the periods before or after PPL's acquisition of LKE on November 1, 2010, and are labeled as Predecessor or Successor. LG&E applied push-down accounting to account for the acquisition. For accounting purposes only, push-down accounting is considered to create a new entity due to new cost basis assigned to assets, liabilities and equity as of the acquisition date. Consequently, LG&E's results of operations and cash flows for the Predecessor and Successor periods in 2010 are shown separately, rather than combined, in its audited financial statements.

In the "Management's Discussion and Analysis" of "Results of Operations" and "Financial Condition," the Company has included disclosure of the combined Predecessor and Successor results of operations and cash flows. Such presentation is considered to be a non-GAAP disclosure. LG&E has included such disclosure because the Company believes it facilitates the comparison of 2010 operating and financial performance to 2009 and 2008, and because the core operations of the Company have not changed as a result of the acquisition.

Competition

See the Business section for information concerning competition.

Environmental Matters

General

Protection of the environment is a major priority for LG&E and a significant element of its business activities. Extensive federal, state and local environmental laws and regulations are applicable to LG&E'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 but could be material. In addition, costs may increase significantly if the requirements or scope of environmental laws or regulations, or similar rules, are expanded or changed from prior versions by the relevant agencies. Costs may take the form of increased capital or operating and maintenance expenses; monetary fines, penalties or forfeitures or other restrictions. Many of these environmental law considerations are also applicable to the operations of key suppliers, or customers, such as coal producers, industrial power users, etc., and may impact the costs of their products or their demand for LG&E's services.

Climate Change

Recent developments continue to indicate an increased possibility of significant climate change or GHG legislation or regulation, at the international, federal, regional and state levels. During December 2009, as part of the United Nation's Copenhagen Accord, the United States agreed to a non-binding goal to reduce GHG emissions to 17% below 2005 levels by 2020. Additionally, during 2009, the U.S. House of Representatives passed comprehensive GHG legislation, which included a number of measures to limit GHG emissions and achieve GHG emission reduction targets below 2005 levels of 3% by 2012, 17% by 2020 and 83% by 2050. Similar legislation has been considered in the U.S. Senate, but the prospects for passage remain uncertain. In late 2009, the EPA issued a final endangerment finding relating to mobile sources of GHGs and a GHG reporting requirement beginning in 2010. In 2010, the EPA issued a final rule requiring implementation of best available control technology for GHG emissions from new or modified power plants, effective January 2011. In December 2010, the EPA announced that it intends to propose New Source Performance Standards addressing GHG emissions from new and existing power plants, with a proposed rule expected in July 2011. Finally, a number of U.S. states, although not currently including Kentucky, have adopted GHG-reduction legislation or regulation of various sorts. The developing GHG initiatives include a number of differing structures and formats, including direct limitations on GHG sources, issuance of allowances for GHG emissions, cap-and-trade programs for such allowances, renewable or alternative generation portfolio standards and mechanisms relating to demand reduction, energy efficiency, smart-grid, transmission expansion, carbon-sequestration or other GHG-reducing efforts. While the final terms and impacts of such initiatives cannot be estimated, LG&E, primarily coal-fired utility, could be highly affected by such proceedings.

Other Environmental Regulatory Initiatives

The EPA has proposed or announced that it intends to propose a number of additional environmental regulations that could substantially impact utilities with coal-fired generating assets. These regulatory initiatives include revisions to the ambient air quality standards for SO_2, NO_2, ozone and particulate matter 2.5 microns in size or less, rules aimed at mitigating the interstate transport of SO_2 and NOx, a program governing emissions of hazardous air pollutants from utility generating units, a program for the management of coal combustion residuals, revised effluent guidelines for utility generating facilities and standards for cooling water intake structures. Such requirements could potentially mandate upgrade of existing emission controls, installation of additional emission controls such as FGDs, SCRs, fabric filter bag houses, activated carbon injection, wet electrostatic precipitators, closure of ash ponds and retrofit of landfills, installation of cooling towers, deployment of new water treatment technologies and retirement of facilities that cannot be retrofitted on a cost effective basis.

The cost to LG&E and the effect on LG&E's business of complying with potential GHG restrictions and other environmental regulatory initiatives will depend upon provisions of any final rules and how the rules are implemented by the EPA. Some of the design elements which may have the greatest effect on LG&E include (a) the required levels and timing of emissions caps, discharge limits or similar standards, (b) the sources covered by such requirements, (c) transition and mitigation provisions, such as phase-in periods, free allowances or price caps, (d) the availability and pricing of relevant mitigation or control technologies, goods or services, and (e) economic, market and customer reaction to electricity price and demand changes due to environmental concerns.

Ultimately, environmental matters or potential environmental matters can represent an important element of current or future potential capital requirements, future unit retirement or replacement decisions, supply and demand for electricity, operating and maintenance expenses or compliance risks for the Company. Based on prior regulatory precedent, LG&E currently anticipates that many of such direct costs may be recoverable by LG&E through rates or other regulatory mechanisms, particularly with respect to coal-related generation, but the availability, timing or completeness of such rate recovery cannot be assured. Ultimately, climate change and other environmental matters will likely increase the level of capital expenditures and operating and maintenance costs incurred by the Company during the next several years. With respect to NAAQS, CATR, CAMR replacement and coal combustion byproducts developments, based on a preliminary analysis of proposed regulations, the Company may be required to consider actions such as upgrading existing emissions controls, installing additional emissions controls, upgrading byproducts disposal and storage and possible early replacement of coal-fired units. In order to comply with the coal combustion residual rules and the above referenced air rules, capital expenditures for LG&E are preliminarily estimated to be in the $1.5 to $1.8 billion range over the next ten years, although final costs may substantially vary. This estimate does not include compliance with GHG rules or contemplated water-related environmental changes. See Risk Factors and Note 13, Commitments and Contingencies, for further information.

Results of Operations

The utility business is affected by seasonal temperatures. As a result, operating revenues (and associated operating expenses) are not generated evenly throughout the year. Revenue and earnings are generally highest during the first and third quarters, and lowest in the second quarter, due to weather.

Net Income

The following table summarizes the significant components of net income for 2010, 2009 and 2008 and the changes therein:

	Combined	Successor	Predecessor		
				Year Ended December 31,	
	Year Ended December 31, 2010	November 1, 2010 through December 31, 2010	January 1, 2010 through October 31, 2010	2009	2008
Total operating revenues	$ 1,311	$ 254	$ 1,057	$ 1,272	$ 1,468
Total operating expenses	1,083	214	869	1,105	1,249
Operating income	228	40	188	167	219
Derivative gain (loss)	19	-	19	18	(37)
Interest expense	23	7	16	17	29
Interest expense to affiliated companies	23	1	22	27	29
Other income (expense) – net	(5)	(3)	(2)	1	7
Income before income taxes	196	29	167	142	131
Income tax expense	68	10	58	47	41
Net income	$ 128	$ 19	$ 109	$ 95	$ 90

The change in LG&E's net income was as follows:

	Increase (Decrease)	
	2010 vs. 2009	2009 vs. 2008
Total operating revenues	$ 39	$ (196)
Total operating expenses	(22)	(144)
Operating income	61	(52)
Derivative gain	1	55
Interest expense	6	(12)
Interest expense to affiliated companies	(4)	(2)
Other income (expense) – net	(6)	(6)
Income before income taxes	54	11
Income taxes	21	6
Net income	$ 33	$ 5

Operating Revenues

Operating revenues follow:

	Combined	Successor	Predecessor		
	Year Ended December 31, 2010	November 1, 2010 through December 31, 2010	January 1, 2010 through October 31, 2010	Year Ended December 31, 2009	Year Ended December 31, 2008
Electric	$ 1,015	$ 169	$ 846	$ 918	$ 1,016
Natural gas	296	85	211	354	452
	$ 1,311	$ 254	$ 1,057	$ 1,272	$ 1,468

The changes in operating revenues were as follows:

	Increase (Decrease)	
	2010 vs. 2009	2009 vs. 2008
Electric	$ 97	$ (98)
Natural gas	(58)	(98)
	$ 39	$ (196)

Electric Revenues

The $97 million increase from 2009 to 2010 and the $98 million decrease from 2008 to 2009 in electric revenues were primarily due to:

	Increase (Decrease)	
	2010 vs. 2009	2009 vs. 2008
Retail sales volumes (a)	$ 46	$ (33)
Base rate price variance (b)	33	(12)
FAC price variance (c)	21	13
Demand revenue (d)	14	2
Merger surcredit termination in February 2009	-	14
Increased recoverable program spending billed through the DSM	3	7
Other operating revenue primarily due to late payment charges	2	4
Transmission sales	1	-
ECR price variance (e)	(7)	7
VDT surcredit termination in August 2008	-	4
Wholesale sales (f)	(16)	(104)
	$ 97	$ (98)

(a) Retail sales volumes increased during 2010 compared to 2009 as a result of increased consumption primarily due to increased heating degree days during the first and fourth quarters of 2010 and increased cooling degree days during the second and third quarters of 2010. Additionally, improved economic conditions in 2010 and significant storm outages in 2009 contributed to the increased volumes.

The decrease in retail sales volumes during 2009 compared to 2008 was attributable to reduced consumption by retail customers as a result of milder weather and weakened economic conditions, in addition to significant storm outages during 2009.

(b) The increase in revenues due to the base rate price variance during 2010 compared to 2009 resulted from higher base rates effective August 1, 2010. As part of the 2010 rate case, the 2001 and 2003 ECR plans were added to rate base, which caused a portion of this increase. See Note 3, Rates and Regulatory Matters, for further discussion of the 2010 Kentucky rate cases.

The decrease in revenues due to the base rate price variance during 2009 compared to 2008 resulted from a reduction in base energy rates effective February 6, 2009. See Note 3, Rates and Regulatory Matters, for further discussion of the 2008 Kentucky rate cases.

(c) FAC revenues increased during 2010 compared to 2009 and 2009 compared to 2008 as a result of increased recoverable fuel costs billed to customers through the FAC due to higher fuel prices.

(d) Demand revenues increased during 2010 compared to 2009 as a result of higher demand rates effective August 1, 2010 and higher customer peak demand. See Note 3, Rates and Regulatory Matters, for further discussion of the 2010 Kentucky rate cases.

Demand revenues increased during 2009 compared to 2008 primarily as a result of higher demand rates effective February 6, 2009, partially offset by lower customer peak demand. See Note 3, Rates and Regulatory Matters, for further discussion of the 2008 Kentucky cases.

(e) The decrease in revenues due to the ECR price variance during 2010 compared to 2009 resulted from lower recoverable capital spending due to the 2001 and 2003 plans being removed from the ECR mechanism.

The increase in revenues due to the ECR price variance during 2009 compared to 2008 resulted from higher recoverable capital spending.

(f) The decrease in wholesale sales during 2010 compared to 2009 was primarily due to lower sales volumes to KU and third party customers and decreased revenues from financial energy swaps. Wholesale volumes decreased as a result of increased consumption by residential customers, due to increased cooling and heating degree days, increased coal-fired generation outages and higher energy usage by industrial customers as a result of improved economic conditions. Financial energy swap revenues decreased as a result of less activity from the buyback of positions in 2010 and a change in the allocation between LG&E and KU in 2009. See Note 15, Related Party Transactions, for further discussion of the mutual agreement for wholesale sales and purchases between the Utilities.

The decrease in wholesale sales during 2009 compared to 2008 resulted from decreased volumes to third party customers as a result of lower economic capacity, scheduled coal-fired generation outages, decreased sales to KU due to lower fuel costs, and decreased third party prices as a result of lower prices in the spot energy market. These decreases were partially offset by increased gains in energy marketing financial swaps.

Natural Gas Revenues

The $58 million decrease from 2009 to 2010 and $98 million decrease from 2008 to 2009 in natural gas revenues were primarily due to:

	Increase (Decrease)	
	2010 vs. 2009	2009 vs. 2008
Reduction in natural gas prices billed through GSC	$ (82)	$ (76)
Retail sales volumes (a)	13	(35)
Retail base rates price variance (b)	10	16
Off-system wholesale sales due to lower demand	-	(6)
Other	1	3
	$ (58)	$ (98)

(a) Retail sales volumes increased during 2010 compared to 2009 as a result of increased consumption was primarily due to colder temperatures during the first and fourth quarters of 2010 and improved economic conditions. The increase in revenues resulting from higher volumes was partially offset by a reduction in WNA.

Retail sales volumes decreased during 2009 compared to 2008 as a result of milder weather and weakened economic conditions. The decrease in the volume variance in 2009 was partially offset by increased WNA revenues resulting from lower natural gas sales volumes.

(b) The increase in revenues due to the base rate price variance during 2010 compared to 2009 resulted from higher base rates effective August 1, 2010. See Note 3, Rates and Regulatory Matters, for further discussion of the 2010 Kentucky rate case.

The increase in revenues due to the base rate price variance during 2009 compared to 2008 was due to the change in base rates resulting from the application of the base rate case settlement in February 2009. See Note 3, Rates and Regulatory Matters, for further discussion of the 2008 Kentucky rate case.

Operating Expenses

Fuel for electric generation and natural gas supply expenses comprise a large component of total operating expenses. Increases or decreases in the cost of fuel and natural gas supply are reflected in electric and natural gas retail rates through the GSC and FAC, subject to the approval of the FERC and the Kentucky Commission. Operating expenses and the changes therein for 2010, 2009 and 2008 follow:

	Combined	Successor	Predecessor		
	Year Ended December 31, 2010	November 1, 2010 through December 31, 2010	January 1, 2010 through October 31, 2010	Year Ended December 31, 2009	Year Ended December 31, 2008
Fuel for electric generation	$ 366	$ 60	$ 306	$ 328	$ 346
Power purchased	55	10	45	59	120
Natural gas supply expense	162	53	109	243	347
Other operation and maintenance expenses	362	68	294	339	309
Depreciation and amortization	138	23	115	136	127
	$ 1,083	$ 214	$ 869	$ 1,105	$ 1,249

The changes in operating expenses were as follows:

	Increase (Decrease) 2010 vs. 2009	Increase (Decrease) 2009 vs. 2008
Fuel for electric generation	$ 38	$ (18)
Power purchased	(4)	(61)
Natural gas supply expense	(81)	(104)
Other operation and maintenance expenses	23	30
Depreciation and amortization	2	9
	$ (22)	$ (144)

Fuel for Electric Generation

The $38 million increase from 2009 to 2010 and $18 million decrease from 2008 to 2009 were primarily due to:

	Increase (Decrease)	
	2010 vs. 2009	2009 vs. 2008
Commodity costs for coal and natural gas	$ 23	$ 2
Fuel usage volumes (a)	17	(20)
Other	(2)	-
	$ 38	$ (18)

(a) Fuel usage volumes increased in 2010 compared to 2009 due to increased native load sales. Fuel usage volumes decreased in 2009 compared to 2008 due to decreased native load and wholesale sales.

Power Purchased Expense

The $4 million decrease from 2009 to 2010 and $61 million decrease from 2008 to 2009 were primarily due to:

	Increase (Decrease)	
	2010 vs. 2009	2009 vs. 2008
Purchases from KU due to volume (a)	$ (7)	$ (60)
Purchases from KU due to prices	(1)	-
Prices for purchases used to serve retail customers	3	(2)
Demand payments for third party purchases	1	2
Third party purchased volumes for native load	-	(1)
	$ (4)	$ (61)

(a) Purchased volumes from KU decreased in 2010 compared to 2009 due to increased demand by the Utilities' native load customers and reduced availability of LG&E's lower cost generation to supply KU's demand as a result of LG&E unit outages.

Purchased volumes from KU decreased in 2009 compared to 2008 as result of LG&E's and KU's scheduled outages at coal-fired generation units during 2009 and as a result of KU's units held in reserve as a result of low spot market pricing for the majority of 2009. See Note 15, Related Party Transactions, for further discussion of the mutual agreement for wholesale sales and purchases between the Utilities.

Natural Gas Supply Expense

The $81 million decrease from 2009 to 2010 and $104 million decrease from 2008 to 2009 were primarily due to:

	Increase (Decrease)	
	2010 vs. 2009	2009 vs. 2008
Cost of natural gas supply billed to customers due to lower cost per Mcf	$ (95)	$ (73)
Natural gas volumes delivered	13	(26)
Wholesale sales of purchased natural gas volumes	-	(5)
Other	1	-
	$ (81)	$ (104)

Other Operation and Maintenance Expenses

The $23 million increase from 2009 to 2010 was primarily due to $8 million of increased other operation expenses and $15 million of increased maintenance expenses. The $30 million increase from 2008 to 2009 was primarily due to $28 million of increased other operation expenses and $2 million of increased maintenance expenses.

Other Operation Expenses:

The $8 million increase from 2009 to 2010 and $28 million increase from 2008 to 2009 were primarily due to:

	Increase (Decrease)	
	2010 vs. 2009	2009 vs. 2008
Administrative and general expense	$ 2	$ 2
Bad debt expense	2	-
DSM program spending	2	10
Transmission expense	2	(3)
Distribution expense	2	(1)
Power supply expense	1	(4)
Pension expense (a)	(4)	24
Other	1	-
	$ 8	$ 28

(a) Pension expense decreased in 2010 compared to 2009 primarily due to favorable asset performance in 2009 and increased in 2009 compared to 2008 primarily due to unfavorable asset performance in 2008.

Other Maintenance Expenses:

The $15 million increase from 2009 to 2010 and $2 million increase from 2008 to 2009 were primarily due to:

	Increase (Decrease)	
	2010 vs. 2009	2009 vs. 2008
Steam expense (a)	$ 9	$ 3
Generation expense (b)	3	-
Administrative and general expense	2	1
Distribution expense	1	(2)
	$ 15	$ 2

(a) Steam expense increased in 2010 compared to 2009 primarily due to increased boiler and electric maintenance expense mainly related to outage work. Steam expense increased in 2009 compared to 2008 due to the timing of scheduled unit outages and routine maintenance.
(b) Generation expense increased in 2010 compared to 2009 primarily due to the overhaul of Paddy's Run Unit 13.

Derivative Gain (Loss)

The $1 million increase from 2009 to 2010 and $55 million increase from 2008 to 2009 were primarily due to:

	Increase (Decrease)	
	2010 vs. 2009	2009 vs. 2008
Reclassification of ineffective interest rate swap loss to a regulatory asset in 2010 (a)	$ 21	$ -
Reclassification of terminated interest rate swap loss to a regulatory asset in 2010 (a)	9	-
Interest expense related to interest rate swaps	2	(2)
Gain (loss) on interest rate swap	(31)	57
	$ 1	$ 55

(a) See Note 3, Rates and Regulatory Matters, for further discussion of the interest rate swap regulatory assets.

Interest Expense

The $2 million increase from 2009 to 2010 and $14 million decrease from 2008 to 2009 were primarily due to:

	Increase (Decrease)	
	2010 vs. 2009	2009 vs. 2008
Bond interest expense (a)	$ 2	$ (4)
Interest rate swaps (b)	1	(8)
Interest expense to affiliated companies (c)	(4)	(2)
Other interest expense	3	-
	$ 2	$ (14)

(a) Bond interest expense increased in 2010 compared to 2009 due to the issuance of first mortgage bonds in November 2010. Bond interest expense decreased in 2009 compared to 2008 due to the repurchase of bonds in 2008. See Note 11, Long-Term Debt, for further information.
(b) See Note 3, Rates and Regulatory Matters, and Note 5, Derivative Financial Instruments, for further information regarding interest rate swaps.
(c) Interest expense to affiliated companies decreased in 2010 compared to 2009 primarily due to notes payable to Fidelia being paid in full in November as a result of the PPL acquisition. Interest expense to affiliated companies decreased in 2009 compared to 2008 as a result of lower interest rates on intercompany short-term borrowings ($6 million), which was partially offset by increased interest expense as a result of additional debt issued during 2008 ($4 million).

Other Income (Expense) – Net

Other income (expense) – net decreased $6 million in 2010 and 2009 primarily due to decreased gains on the sale of Company property.

Income Tax Expense

See Note 10, Income Taxes, for a reconciliation of differences between the U.S. federal income tax expense at statutory rates and LG&E's income tax expense.

2011 Outlook

LG&E projects 2011 earnings to be on par with 2010 as increases associated with the 2010 Kentucky rate case and lower financing costs are offset by a decrease in other income due to the recognition of a regulatory asset associated with the interest rate swaps, as well as higher operation and maintenance expenses and depreciation. Operation and maintenance expenses and depreciation are expected to increase due to placing TC2 in service in January 2011. See Risk Factors for a discussion of the risk factors that may impact the 2011 outlook.

Financial Condition

Liquidity and Capital Resources

LG&E expects to continue to have adequate liquidity available through operating cash flows, cash and cash equivalents and its credit facilities. LG&E remarketed $163 million of pollution control bonds in January 2011 and expects to remarket an additional $25 million of pollution control bonds in November 2011. LG&E currently has no other plans to access debt capital markets in 2011. See Note 19, Subsequent Events, for further information.

LG&E's cash flows from operations and access to cost-effective bank and capital markets are subject to risks and uncertainties including, but not limited to, the following:

- changes in market prices for electricity;
- potential ineffectiveness of the trading, marketing and risk management policy and programs used to mitigate LG&E's risk exposure to adverse electricity and fuel prices and interest rates;

- operational and credit risks associated with selling and marketing products in the wholesale power markets;
- unusual or extreme weather that may damage LG&E's transmission and distribution facilities or affect energy sales to customers;
- unavailability of generating units (due to unscheduled or longer than anticipated generation outages, weather and natural disasters) and the resulting loss of revenues and additional costs of replacement electricity;
- ability to recover and the timeliness and adequacy of recovery of costs ;
- costs of compliance with existing and new environmental laws;
- any adverse outcome of legal proceedings and investigations with respect to LG&E's current and past business activities;
- deterioration in the financial markets that could make obtaining new sources of bank and capital markets funding more difficult and more costly; and
- a downgrade in LG&E's credit ratings that could adversely affect its ability to access capital and increase the cost of credit facilities and any new debt.

See the Risk Factors section for further discussion of risks and uncertainties affecting LG&E's cash flows.

At December 31, LG&E had the following:

	Successor	Predecessor
	2010	2009
Cash and cash equivalents	$ 2	$ 5
Available for sale debt securities (a)	163	-
	$ 165	$ 5
Current portion of long-term debt (b)	$ -	$ 120
Notes payable to affiliated companies (c)	12	170
Note payable (d)	163	-
	$ 175	$ 290

(a) 2010 amount represents tax-exempt bonds issued by Louisville/Jefferson County, Kentucky, on behalf of LG&E that were subsequently purchased by LG&E. Such bonds were remarketed to unaffiliated investors in January 2011. See Note 18, Available for Sale Debt Securities, and Note 19, Subsequent Events, for further information.

(b) 2009 amount represents Jefferson County 2001 Series A and B and Trimble County 2001 Series A and B pollution control bonds subject to tender for purchase at the option of the holder and to mandatory tender for purchase upon the occurrence of certain events. The Successor has classified these bonds as long-term because the Company has the intent and ability to utilize its $400 million credit facility which matures in December 2014, to fund any mandatory purchases. The Predecessor classified these bonds as the current portion of long-term debt due to the tender for purchase provisions. The Predecessor presentation and the Successor presentation are both appropriate under GAAP. See Note 1, Summary of Significant Accounting Policies and Note 11, Long-Term Debt, for further information.

(c) Amounts represent borrowings under LG&E's intercompany money pool agreement wherein LKE and/or KU make funds available to LG&E at market-based rates of up to $400 million. See Note 12, Notes Payable and Other Short-Term Obligations, for further information.
(d) 2010 amount represents borrowings on LG&E's $400 million revolving line of credit with a group of banks. See Note 12, Notes Payable and Other Short-Term Obligations, for further information.

A condensed table of cash flows for the following periods in 2010, 2009 and 2008 is presented below. The Predecessor period, January 1, 2010 through October 31, 2010, and the Successor period, November 1, 2010 through December 31, 2010, were aggregated without further adjustment for purposes of comparison with the same periods in 2009 and 2008.

	Combined	Successor	Predecessor		
	Year Ended December 31, 2010	November 1, 2010 through December 31, 2010	January 1, 2010 through October 31, 2010	Year Ended December 31, 2009	Year Ended December 31, 2008
Net cash provided by (used in) operating activities	$ 181	$ (8)	$ 189	$ 309	$ 197
Net cash provided by (used in) investing activities	(170)	(63)	(107)	(176)	(232)
Net cash provided by (used in) financing activities	(14)	69	(83)	(132)	35
Change in cash and cash equivalents	$ (3)	$ (2)	$ (1)	$ 1	$ -

Operating Activities

Net cash provided by operating activities decreased by 41%, or $128 million, in 2010 compared with 2009, primarily as a result of changes in working capital, refunds of prior year GSC over-collections, higher interest payments due to an accelerated settlement with the previous owner and higher income tax payments due to higher taxable income. These decreases in cash flow were partially offset by increased earnings and lower storm expenses.

Net cash provided by operating activities increased by 57%, or $112 million, in 2009 compared with 2008, primarily as a result of increased GSC recoveries and favorable changes in working capital. These increases in cash flow were partially offset by lower earnings excluding derivative gains and losses, higher storm expenses and increased pension funding.

LG&E expects to achieve relatively stable cash flows from operations during the next three years although future cash flows may be significantly impacted by changes in economic conditions or new environmental and tax regulations.

Investing Activities

The primary use of cash in investing activities is capital expenditures. See "Forecasted Uses of Cash" for details regarding projected capital expenditures for the years 2011 through 2013.

Net cash used in investing activities decreased by 3%, or $6 million, in 2010 compared with 2009, primarily as a result of additional proceeds received of $45 million on the sale of assets and an increase of $2 million in restricted cash collections. These increases in cash flow were partially offset by $34 million in higher capital expenditures and a decrease of $7 million in cash received on the settlement of derivatives.

Net cash used in investing activities decreased by 24%, or $56 million, in 2009 compared with 2008, primarily as a result of a decrease of $57 million in capital expenditures and an increase of $15 million in cash received on the settlement of derivatives, partially offset by $16 million less in proceeds received on the sale of assets.

Financing Activities

Net cash used in financing activities was $14 million in 2010 compared with $132 million in 2009. The change from 2009 to 2010 is a result of new long-term debt issued in excess of retirements, lower dividend payments and less short-term debt repayment.

Net cash used in financing activities was $132 million in 2009 compared with cash provided by financing activities totaling $35 million in 2008. The lower level of cash provided by financing in 2009 was the result of higher dividends and the repayment of short-term debt partially offset by fewer retirements and repurchases of long-term debt.

In the two months of 2010 following the acquisition, cash provided by financing activities of the Successor primarily consisted of the issuance of first mortgage bonds totaling $531 million after discounts, the issuance of intercompany notes totaling $485 million to a PPL subsidiary to repay debt due to an E.ON affiliate upon the closing of the sale and a $163 million drawing under a revolving line of credit. These amounts were offset by the repayment of $485 million to an E.ON affiliate upon the closing of the sale, the repayment of $485 million to a PPL affiliate upon the issuance of the first mortgage bonds, the repayment of $130 million of short-term borrowings due to an affiliated company and the payment of $10 million of debt issuance costs.

In 2010, cash used in financing activities by the Predecessor primarily consisted of the payment of $55 million of dividends to LKE and decreases in short-term borrowings due to an affiliated company totaling $28 million.

In 2009, cash used in financing activities primarily consisted of the payment of dividends to LKE totaling $80 million and the repayment of $52 million of short-term borrowings due to an affiliated company.

In 2008, cash provided by financing activities primarily consisted of an increase in short-term borrowings due to an affiliated company of $144 million, the issuance of $95 million of pollution control revenue bonds, the issuance of $75 million of intercompany notes to an E.ON affiliate and the receipt of capital contributions from LKE totaling $20 million, partially offset by the repurchase of $259 million of pollution control revenue bonds and the payment of $40 million in dividends to LKE.

LG&E's debt financing activity in 2010 was:

	Issuances (a)	Retirements
Short-term borrowings from affiliated company – net change	$ -	$ (158)
Other borrowings from affiliated company	485	(485)
Borrowings from an E.ON affiliate	-	(485)
Issuance of short-term note payable	163	-
Issuance of bonds	531	-
Net change in debt financing	$ 1,179	$ (1,128)

(a) Issuances are net of pricing discounts, where applicable.

See Note 11, Long-Term Debt, for further information.

Working Capital Deficiency

As of December 31, 2009, LG&E had a working capital deficiency of $150 million, primarily due to notes payable to affiliated companies totaling $170 million and $120 million of tax-exempt bonds which allow the investors to put the bonds back to the Company causing them to be classified as "Current portion of long-term debt." As of December 31, 2010, the Company no longer had a working capital deficiency because the majority of the notes payable to affiliated companies were paid off in conjunction with the PPL acquisition, the $120 million of tax-exempt bonds were no longer classified as "Other current liabilities" by the Successor because the Company has the intent and ability to utilize its $400 million credit facility which expires in December 2014 to fund any mandatory purchases, and the $163 million in repurchased pollution control bonds that were previously reported on a net basis by the Predecessor are now reported on a gross basis as available for sale debt securities by the Successor. See Note 11, Long-Term Debt, Note 18, Available for Sale Debt Securities, and Note 19, Subsequent Events, for further information.

Auction Rate Securities

Auctions for auction rate securities issued by LG&E continued to fail throughout 2010. LG&E held $163 million of its own securities at December 31, 2010 and December 31, 2009, that at one time were auction rate securities. These pollution control bonds were reissued in January 2011. See Note 11, Long-Term Debt, Note 18, Available for Sale Debt Securities, and Note 19, Subsequent Events, for further discussion.

Forecasted Sources of Cash

LG&E expects to continue to have adequate sources of cash available in the near term, including access to external financing, financing from affiliates and/or infusions of capital from LKE. Regulatory approvals are required for LG&E to incur additional debt. The FERC authorizes the issuance of short-term debt while the Kentucky Commission authorizes the issuance of long-term debt. In November 2009, LG&E received a two-year authorization from the FERC to borrow up to $400 million in short-term funds. Short-term funds are made available via the Company's participation in an intercompany money pool agreement wherein LKE and/or KU make funds available to LG&E at market-based rates (based on highly rated commercial paper issues) up to $400 million or via the $400 million Revolving Credit Agreement discussed below. LG&E currently believes this authorization and these facilities, together with the Company's credit facilities discussed below, provide the necessary flexibility to address any liquidity needs.

Credit Facilities

On November 1, 2010, LG&E entered into a $400 million unsecured Revolving Credit Agreement with a group of banks. Under this new credit facility, which expires on December 31, 2014, LG&E has the ability to make cash borrowings and to request the lenders to issue letters of credit. Borrowings will generally bear interest at LIBOR-based rates plus a spread, depending upon LG&E's senior unsecured long-term debt rating. The new credit facility contains financial covenants requiring LG&E's debt to total capitalization to not exceed 70% and other customary covenants. As of December 31, 2010, LG&E's debt to total capitalization was 43% as calculated pursuant to the credit agreement. Under certain conditions, LG&E may request that the facility's capacity be increased by up to $100 million. This new credit facility replaced three bilateral credit facilities totaling $125 million that were terminated November 1, 2010. As of December 31, 2010, there were $163 million of borrowings outstanding under the new credit facility. In January 2011, LG&E successfully remarketed $163 million of its repurchased pollution control bonds and used the proceeds to repay the outstanding balance on LG&E's credit facility. LG&E will utilize unused credit facility and money pool balances to fund working capital needs as they arise. See Note 11, Long-Term Debt, Note 18, Available for Sale Debt Securities, and Note 19, Subsequent Events, for further information regarding the Company's remarketed bonds. See Note 12, Notes Payable and Other Short-Term Obligations, for further information regarding the Company's credit facilities.

Contributions from LKE

LKE may make capital contributions to LG&E, which can be used for general business purposes.

Long-Term Debt

LG&E currently does not plan to issue any new long-term debt in 2011. However, LG&E remarketed $163 million of pollution control bonds in January 2011 and expects to remarket an additional $25 million of pollution control bonds in the second half of 2011. See Note 19, Subsequent Events, for further information.

<u>Forecasted Uses of Cash</u>

In addition to expenditures required for normal operating activities, such as fuel for electric generation, power purchased, payroll and taxes; LG&E currently expects to incur future cash outflows for capital expenditures, various contractual obligations and the payment of dividends.

Capital Requirements

LG&E'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. LG&E plans to fund capital expenditures through operating cash flows, the credit facility and, if needed, the issuance of long-term debt. LG&E expects its capital expenditures for the three year period ending December 31, 2013, to total approximately $1,569 million, consisting primarily of the following:

Construction of environmental controls and capacity replacement	$	731
Construction of distribution and metering assets		389
Construction of generation assets		169
Construction of coal combustion residual storage structures		90
Redevelopment of Ohio Falls hydroelectric facility		67
Information technology projects		41
Construction of transmission assets		40
Other projects		26
Recoverable environmental assets		16
	$	1,569

The Company's capital program will focus primarily on compliance with existing or anticipated EPA environmental regulations, aging infrastructure and the need for increased storage capacity for coal combustion by-product materials over the next several years. This program may also 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 and other regulatory requirements. In particular, climate change initiatives, whether via legislative, regulatory or market channels, could restrict or disadvantage power generation from higher-carbon sources. Therefore, LG&E has included estimates regarding significant additional capital expenditures related to pending environmental regulations and legislation. These estimates are subject to final regulations and least cost analysis based on engineering studies. To the extent financial markets see climate change as a potential risk, LG&E may face reduced access to or increased costs in capital markets. Capital expenditures for LG&E associated with such actions are preliminarily estimated to be in the $1.5 to $1.8 billion range over the next ten years, although final costs may substantially vary.

See the contractual obligations table below and Note 13, Commitments and Contingencies, for further information concerning commitments.

Contractual Obligations

The following is provided to summarize contractual cash obligations for periods after December 31, 2010. LG&E anticipates cash from operations and external financing will be sufficient to fund future obligations. See the Statements of Capitalization.

	Payments Due by Period						
	2011	2012	2013	2014	2015	Thereafter	Total
Short-term debt (a)	$ 175	$ -	$ -	$ -	$ -	$ -	$ 175
Long-term debt (b)	-	-	-	-	250	859	1,109
Interest on long-term debt (c)	32	33	36	39	43	826	1,009
Operating leases (d)	5	4	3	3	2	1	18
Unconditional power purchase obligations (e)	20	22	22	23	22	258	367
Coal and natural gas purchase obligations (f)	334	109	112	98	100	36	789
Pension benefit plan obligation (g)	28	33	30	6	1	3	101
Postretirement benefit plan obligations (h)	7	7	7	7	7	35	70
Construction obligations (i)	118	6	4	-	-	-	128
Other obligations (j)	1	1	-	-	-	-	2
	$ 720	$ 215	$ 214	$ 176	$ 425	$ 2,018	$ 3,768

This table does not reflect contingent obligations. See Note 13, Commitments and Contingencies, for further information on contingent obligations.

(a) Represents borrowings of $12 million of debt due to affiliates and debt due to external parties of $163 million within one year.
(b) Reflects principal maturities only based on legal maturity dates and includes the current portion of long-term debt.
(c) Assumes interest payments through maturity. The payments herein are subject to change as payments for debt that is or becomes variable-rate debt have been estimated.
(d) Represents future operating lease payments.
(e) Represents future minimum payments under OVEC power purchase agreements through March 13, 2026.
(f) Represents contracts to purchase coal, natural gas and natural gas transportation.
(g) Represents projected cash flows for funding the pension benefit plans as calculated by the actuary. For pension funding information see Note 9, Pension and Other Postretirement Benefit Plans.
(h) Represents projected cash flows for the postretirement benefit plan as calculated by the actuary. For postretirement funding information, see Note 9, Pension and Other Postretirement Benefit Plans.

(i) Represents construction commitments, including commitments for the Ohio Falls refurbishment and the Trimble landfill construction including the associated material transport systems for coal combustion residuals.

(j) Represents other contractual obligations including the SPP and TVA coordination agreements.

Pension and Postretirement Benefit Plans

See Application of Critical Accounting Policies and Estimates for discussion regarding discretionary contributions to the pension and postretirement benefit plans in 2011.

Dividends

Future dividends may be declared at the discretion of LG&E's Board of Directors, payable to its sole shareholder, LKE. As discussed in Note 12, Notes Payable and Other Short-Term Obligations, LG&E's dividend payments are limited under a covenant in its $400 million revolving line of credit facility. This covenant restricts the debt to total capital ratio to not more than 70%. LG&E is subject to Section 305(a) of the Federal Power Act, which makes it unlawful for a public utility to make or pay a dividend from any funds "properly included in capital account." The meaning of this limitation has never been clarified under the Federal Power Act. LG&E believes, however, that this statutory restriction, as applied to its circumstances, would not be construed or applied by the FERC to prohibit the payment from retained earnings of dividends that are not excessive and are for lawful and legitimate business purposes.

Purchase, Redemption or Remarketing of Debt Securities

In January 2011, LG&E successfully remarketed $163 million of its repurchased pollution control bonds, which were classified as "Available for sale debt securities" on the Balance Sheets at December 31, 2010. LG&E used the proceeds from the remarketed bonds to repay the balance of its credit facility. LG&E will continue to evaluate purchasing, redeeming or remarketing outstanding debt securities and may decide to take action depending upon prevailing market conditions and available cash.

See Note 11, Long-Term Debt, Note 18, Available for Sale Debt Securities, and Note 19, Subsequent Events, for further information regarding the Company's remarketed bonds. See Note 12, Notes Payable and Other Short-Term Obligations, for discussion regarding the Company's credit facilities.

Credit Ratings

LG&E's credit ratings reflect the views of three national rating agencies. 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. In October 2010, one national rating agency revised downward the short-term credit rating of the pollution control bonds and the issuer rating of the Company as a result of the then pending acquisition by PPL. Another raised the long-term rating of the pollution control bonds as a result of the addition of the first mortgage bonds as collateral. In October 2010, a third national rating agency provided an initial rating of the Company's pollution control bonds and first mortgage bonds. See Note 11, Long-Term Debt, for a discussion of downgrade actions in 2009 and 2008 related to the pollution control bonds caused by a change in the rating of the entity insuring those bonds.

Ratings Triggers

LG&E has various derivative and non-derivative contracts, including contracts for the sale and purchase of electricity and fuel and commodity transportation and interest rate instruments, which contain provisions requiring LG&E to post additional collateral, or permit the counterparty to terminate the contract if LG&E's credit rating were to fall below investment grade. See Note 5, Derivative Financial Instruments, for a discussion of Credit Risk Related Contingent Features, including a discussion of the potential additional collateral that would have been required for derivative contracts in a net liability position at December 31, 2010. At December 31, 2010, if LG&E's credit ratings had been below investment grade, LG&E would have been required to prepay or post an additional $83 million of collateral to counterparties for both derivative and non-derivative commodity and commodity-related contracts used in its generation, marketing and trading operations and interest rate contracts.

Off-Balance Sheet Arrangements

LG&E has very limited off-balance sheet activity. See Note 13, Commitments and Contingencies, for further discussion.

Risk Management

Credit Risk

LG&E is exposed to potential losses as a result of nonperformance by counterparties of their contractual obligations. LG&E maintains credit policies and procedures to limit counterparty credit risk including evaluating credit ratings and financial information along with having certain counterparties post margin if the credit exposure exceeds certain thresholds. See Note 5, Derivative Financial Instruments, for information regarding risk management activities.

LG&E is exposed to potential losses as a result of nonpayment by customers. The Company maintains an allowance for doubtful accounts composed of accounts aged more than four months. Accounts are written off as management determines them uncollectible. See Application of Critical Accounting Policies and Estimates and Note 1, Summary of Significant Accounting Policies, for further discussion.

Certain of the Company's derivative instruments contain provisions that require it to provide immediate and on-going collateralization on derivative instruments in net liability positions based upon the Company's credit ratings from each of the major credit rating agencies. See Note 5, Derivative Financial Instruments, for information regarding exposure and the risk management activities.

Liquidity Risk

LG&E expects to continue to have access to adequate sources of liquidity through operating cash flows, cash and cash equivalents, credit facilities and/or infusion of capital from its parent. See Financial Condition - Liquidity and Capital Resources for an expanded discussion of LG&E's liquidity position and a discussion of its forecasted sources of cash.

Securities Price Risk

LG&E has securities price risk through its participation in defined benefit pension and postretirement benefit plans. Declines in the market price of debt and equity securities could impact contribution requirements. See Application of Critical Accounting Policies and Estimates – Defined Benefits for a discussion of the assumptions and sensitivities regarding the Company's defined benefit pension and postretirement benefit plans assumptions.

Interest Rate and Commodity Price Risk

LG&E is subject to interest rate and commodity price risk related to on-going business operations. It currently manages commodity risks using derivative instruments, including swaps and forward contracts. The Company's policies allow for the interest rate risk to be managed through the use of fixed rate debt, floating rate debt and interest rate swaps. At December 31, 2010, the Company's annual exposure to increased interest expense, based on a 10% increase in interest rates, was less than $1 million.

LG&E manages price risk by conducting energy trading activities through forward financial transactions. The following chart sets forth the net fair value of LG&E's commodity derivative contracts. See Note 5, Derivative Financial Instruments, for further information.

	Successor	Predecessor	
	December 31, 2010	October 31, 2010	December 31, 2009
Fair value of contracts outstanding at the beginning of the period	$ -	$ -	$
Contracts realized or otherwise settled during the period	-	3	10
Fair value of new contracts entered into during the period	-	(4)	1
Other changes in fair value (a)	(1)	1	(12)
Fair value of contracts outstanding at the end of the period	$ (1)	$ -	$ -

(a) Represents the change in value of outstanding transactions and the value of transactions entered into and settled during the period.

Related Party Transactions

LG&E and its Parent, LKE and subsidiaries of LKE engage in related party transactions. See Note 15, Related Party Transactions, for further information.

LG&E is not aware of any material ownership interest or operating responsibility by the executive officers of LG&E in outside partnerships, including leasing transactions with variable interest entities, or entities doing business with LG&E.

Acquisitions, Development and Divestitures

LG&E and KU have been constructing a new 760-Mw capacity base-load, coal-fired unit, TC2, which is jointly owned by LG&E (14.25%) and KU (60.75%), together with IMEA and IMPA (combined 25%). With limited exceptions the Company took care, custody and control of TC2 on January 22, 2011, and has dispatched the unit to meet customer demand since that date. LG&E and the contractor agreed to a further amendment of the construction agreement whereby the contractor will complete certain actions relating to identifying and completing any necessary modifications to allow operation of TC2 on all fuels in accordance with initial specifications prior to certain dates, and amending the provisions relating to liquidated damages. See Note 13, Commitments and Contingencies, for further information.

LG&E continuously re-examines development projects based on market conditions and other factors to determine whether to proceed, to cancel or to expand the projects.

Application of Critical Accounting Policies and Estimates

The financial statements of LG&E are prepared in compliance with GAAP. The application of these principles 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 also 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. LG&E's senior management has reviewed the significant and critical accounting policies with the relevant governing bodies of the Company and its parent, as applicable.

An accounting policy is deemed to be critical if it requires an accounting estimate to be made based on assumptions about matters that are highly uncertain at the time the estimate is made, if different estimates reasonably could have been used or if changes in the estimate that are reasonably possible could materially impact the financial statements. Management believes the following critical accounting policies reflect the significant estimates and assumptions used in the preparation of the Financial Statements.

Price Risk Management

See Financial Condition - Risk Management.

Regulatory Mechanisms

LG&E is a cost-based rate-regulated utility. As a result, the financial statements reflect the effects of regulatory actions. Regulatory assets are recognized for the effect of transactions or events where future recovery is probable in regulated customer rates. The effect of such accounting is to defer certain or qualifying costs that would otherwise be charged to expense. Likewise, regulatory liabilities are recognized for obligations expected to be returned through future regulated customer rates. The effect of such transactions or events would otherwise be reflected as income, or, in certain cases, regulatory liabilities are recorded based on the understanding with the regulator that current rates are being set to recover costs that are expected to be incurred in the future. The regulated entity is accountable for any amounts charged pursuant to such rates and not yet expended for the intended purpose. The accounting for regulatory assets and liabilities is based on specific ratemaking decisions or precedent for each transaction or event as prescribed by the FERC and the Kentucky Commission. See Note 3, Rates and Regulatory Matters, for additional detail regarding regulatory assets and liabilities.

Defined Benefits

LG&E employees benefit from both funded and unfunded retirement benefit plans. See Note 1, Summary of Significant Accounting Policies, for information about policy changes between the Predecessor and Successor and the accounting for defined benefits including LG&E's method of amortizing gains and losses. LG&E makes various assumptions in arriving at pension and other postretirement benefit costs and obligations. The major assumptions include:

- LG&E's selection of discount rates is based on the Mercer Pension Discount Yield Curve (Predecessor) and the Towers Watson Yield Curve (Successor).
- LG&E's selection of rate of salary growth is based on historical data that includes employees' periodic pay increases and promotions, which are used to project employees' pension benefits at retirement.
- LG&E determines the expected long-term return on plan assets based on the current level of expected return 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 is then weighted based on the current asset allocation.
- LG&E's management projects health care cost trends based on past health care costs, the near-term outlook and an assessment of likely long-term trends.

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 return on investments within the plans was approximately 12% for the year ended December 31, 2010. The benefit plan assets and obligations are re-measured annually using a December 31 measurement date. Due to the PPL acquisition, the benefit plan assets and obligations were also re-measured at October 31, 2010. The Company's 2010 pension and postretirement benefit cost was approximately $6 million less than 2009. The Company anticipates its 2011 pension cost will be approximately $4 million less than the 2010 expense. The amount of future funding will depend upon the actual return on plan assets, the discount rate and other factors, but the Company funds its pension obligations in a manner consistent with the Pension Protection Act of 2006. The Company made discretionary contributions to its pension plan of $20 million and $8 million in 2010 and 2009, respectively. In January 2011, LG&E contributed $64 million to its pension plans. See Note 19, Subsequent Events, for further information.

See Note 9, Pension and Other Postretirement Benefit Plans, for further information on defined benefits including sensitivity analysis expressing potential changes in expected returns that would result from hypothetical changes to assumptions and estimates, expected rate of return assumptions and health care trends.

Asset Impairment

LG&E performs a quarterly review to determine if an impairment analysis is required for long-lived assets that are subject to depreciation or amortization. This review identifies changes in circumstances indicating that a long-lived asset's carrying value may not be recoverable. An impairment analysis will be performed if warranted based on the review. For these long-lived assets, such events or changes in circumstances which may indicate an impairment analysis is required include:

- a significant decrease in the market price of an asset;
- a significant adverse change in the manner in which an asset is being used or in its physical condition;
- a significant adverse change in legal factors or in the business climate;
- an accumulation of costs significantly in excess of the amount originally expected for the acquisition or construction of an asset;
- a current-period operating or cash flow loss combined with a history of losses or a forecast that demonstrates continuing losses;
- a current expectation that, more likely than not, an asset will be sold or otherwise disposed of before the end of its previously estimated useful life; and
- a significant change in the physical condition of an asset.

For a long-lived asset, impairment is recognized when the carrying amount of the asset is not recoverable and exceeds its fair value. The carrying amount is not recoverable if it exceeds the sum of the undiscounted cash flows expected to result from the use and eventual disposition of the asset. If the asset is impaired, an impairment loss is recorded to adjust the asset's carrying value to its estimated fair value. Management must make significant judgments to estimate future cash flows including the useful lives of long-lived assets, the fair value of the assets and management's intent to use the assets. LG&E did not recognize an impairment of any long-lived asset in 2010.

Effective with PPL's acquisition of LKE on November 1, 2010, LG&E recorded $389 million of goodwill. At December 31, 2010, LG&E's goodwill remained unchanged. GAAP requires goodwill to be tested for impairment on an annual basis or more frequently if events or circumstances indicate that assets may be impaired. LG&E performs its annual goodwill impairment test in the fourth quarter. See Note 7, Goodwill and Intangible Assets, for further discussion.

Goodwill is tested for impairment using a two-step approach. In step 1, the Company identifies a potential impairment by comparing the estimated fair value of the Company (the goodwill reporting unit) to its carrying value, including goodwill, on the measurement date. If the estimated fair value exceeds its carrying amount, goodwill is not considered impaired. If the carrying amount exceeds the estimated fair value, the second step is performed to measure the amount of impairment loss, if any.

The second step requires a calculation of the implied fair value of goodwill. The implied fair value of goodwill is determined in the same manner as the amount of goodwill in a business combination. That is, the estimated fair value is allocated to all of LG&E's assets and liabilities as if LG&E had been acquired in a business combination and the estimated fair value of LG&E was the price paid. The excess of the estimated fair value of LG&E over the amounts assigned to its assets and liabilities is the implied fair value of goodwill. The implied fair value of goodwill is then compared with the carrying amount of that goodwill. If the carrying amount exceeds the implied fair value, an impairment loss is recognized in an amount equal to that excess. The loss recognized cannot exceed the carrying amount of the reporting unit's goodwill.

Determining the fair value of LG&E is judgmental in nature and involves the use of significant estimates and assumptions. These estimates and assumptions can include revenue growth rates and operating margins used to calculate projected future cash flows, risk adjusted discount rates and future economic and market conditions.

LG&E tested goodwill for impairment in the fourth quarter of 2010 and no impairment was recognized. See Note 7, Goodwill and Intangible Assets, for further discussion.

Loss Accruals

LG&E accrues losses for the estimated impacts of various conditions, situations or circumstances involving uncertain or contingent future outcomes. For loss contingencies, the loss must be accrued if (1) information is available that indicates it is probable that a loss has been incurred, given the likelihood of the uncertain future events and (2) the amount of the loss can be reasonably estimated. Accounting guidance defines "probable" as cases in which "the future event or events are likely to occur." LG&E does not record the accrual of contingencies that might result in gains, unless recovery is assured. LG&E continuously assesses potential loss contingencies for environmental remediation, litigation claims, regulatory penalties and other events.

The accounting aspects of estimated loss accruals include (1) the initial identification and recording of the loss, (2) the determination of triggering events for reducing a recorded loss accrual and (3) the ongoing assessment as to whether a recorded loss accrual is sufficient. All three of these aspects require significant judgment by LG&E's management. LG&E uses its internal expertise and outside experts (such as lawyers and engineers), as necessary, to help estimate the probability that a loss has been incurred and the amount or range of the loss.

LG&E has identified certain other events that could give rise to a loss, but that do not meet the conditions for accrual. Such events are disclosed, but not recorded, when it is reasonably possible that a loss has been incurred. Accounting guidance defines "reasonably possible" as cases in which "the future event or events occurring is more than remote, but less than likely to occur." See Note 13, Commitments and Contingencies, for disclosure of other potential loss contingencies that have not met the criteria for accrual.

When an estimated loss is accrued, LG&E identifies, where applicable, the triggering events for subsequently adjusting the loss accrual. The triggering events generally occur when the contingency has been resolved and the actual loss is incurred, or when the risk of loss has diminished or been eliminated. The following are some of the triggering events that provide for the adjustment of certain recorded loss accruals:

- Allowances for uncollectible accounts are reduced when accounts are written off after prescribed collection procedures have been exhausted, a better estimate of the allowance is determined or underlying amounts are ultimately collected.
- Environmental and other litigation contingencies are reduced when the contingency is resolved, LG&E makes actual payments, a better estimate of the loss is determined or the loss is no longer considered probable.

LG&E reviews its loss accruals on a regular basis to assure that the recorded potential loss exposures are appropriate. This involves ongoing communication and analyses with internal and external legal counsel, engineers, operation management and other parties. This review may result in the increase or decrease of the loss accrual.

Asset Retirement Obligations

LG&E is required to recognize a liability for legal obligations associated with the retirement of long-lived assets. The initial obligation is measured at its estimated fair value. An equivalent amount is recorded as an increase in the value of the capitalized asset and allocated to expense over the useful life of the asset. Until the obligation is settled, the liability is increased, through the recognition of accretion expense in the Statements of Income, for changes in the obligation due to the passage of time. An offsetting regulatory asset is recognized to reverse the depreciation and accretion expense related to the ARO such that there is no income statement impact. The regulatory asset is relieved when the ARO has been settled. An ARO must be recognized when incurred if the fair value of the ARO can be reasonably estimated.

In determining AROs, management must make significant judgments and estimates to calculate fair value. Fair value is developed using an expected present value technique based on assumptions of market participants that considers estimated retirement costs in current period dollars that are inflated to the anticipated retirement date and then discounted back to the date the ARO was incurred. Changes in assumptions and estimates included within the calculations of the fair value of AROs could result in significantly different results than those identified and recorded in the financial statements. Estimated ARO costs and settlement dates, which affect the carrying value of various AROs and the related assets, are reviewed periodically to ensure that any material changes are incorporated into the estimate of the obligations. Any change to the capitalized asset is amortized over the remaining life of the associated long-lived asset. See Note 4, Asset Retirement Obligations, for further information on AROs.

At December 31, 2010, LG&E had AROs totaling $49 million recorded on the Balance Sheets. Of the total amount, $29 million, or 59%, relates to LG&E's ash ponds, landfills and natural gas mains. The most significant assumptions surrounding AROs are the forecasted retirement costs, the discount rates and the inflation rates. A variance in the forecasted retirement costs, the discount rates or the inflation rates could have a significant impact on the ARO liabilities.

The following chart reflects the sensitivities related to LG&E's ARO liabilities for ash ponds, landfills and natural gas mains as of December 31, 2010:

	Change in Assumption	Impact on ARO Liability
Retirement cost	10%/(10)%	$3/$(3)
Discount rate	0.25%/(0.25)%	$(2)/$2
Inflation rate	0.25%/(0.25)%	$2/$(2)

Income Tax Uncertainties

Significant management judgment is required in developing LG&E's provision for income taxes primarily due to the uncertainty related to tax positions taken or expected to be taken in tax returns and the determination of deferred tax assets, liabilities and valuation allowances.

Significant management judgment is required to determine the amount of benefit recognized related to an uncertain tax position. LG&E evaluates its tax positions following a two-step process. The first step requires an entity to determine whether, based on the technical merits supporting a particular tax position, it is more likely than not (greater than a 50% chance) that the tax position will be sustained. This determination assumes that the relevant taxing authority will examine the tax position and is aware of all the relevant facts surrounding the tax position. The second step requires an entity to recognize in the financial statements the benefit of a tax position that meets the more-likely-than-not recognition criterion. The benefit recognized is measured at the largest amount of benefit that has a likelihood of realization, upon settlement, that exceeds 50%. LG&E's management considers a number of factors in assessing the benefit to be recognized, including negotiation of a settlement.

On a quarterly basis, LG&E reassesses its uncertain tax positions by considering information known at the reporting date. Based on management's assessment of new information, LG&E may subsequently recognize a tax benefit for a previously unrecognized tax position, de-recognize a previously recognized tax position or re-measure the benefit of a previously recognized tax position. The amounts ultimately paid upon resolution of issues raised by taxing authorities may differ materially from the amounts accrued and may materially impact LG&E financial statements in the future.

The balance sheet classification of unrecognized tax benefits and the need for valuation allowances to reduce deferred tax assets also require significant management judgment. LG&E classifies unrecognized tax benefits as current, to the extent management expects to settle an uncertain tax position, by payment or receipt of cash, within one year of the reporting date. Valuation allowances are initially recorded and reevaluated each reporting period by assessing the likelihood of the ultimate realization of a deferred tax asset. Management considers a number of factors in assessing the realization of a deferred tax asset, including the reversal of temporary differences, future taxable income and ongoing prudent and feasible tax planning strategies. Any tax planning strategy utilized in this assessment must meet the recognition and measurement criteria utilized by LG&E to account for an uncertain tax position. See Note 10, Income Taxes, for the required disclosures.

At December 31, 2010, LG&E's existing reserve exposure to either increases or decreases in unrecognized tax benefits during the next 12 months is less than $1 million. This change could result from subsequent recognition, de-recognition and/or changes in the measurement of uncertain tax positions. The events that could cause these changes are direct settlements with taxing authorities, litigation, legal or administrative guidance by relevant taxing authorities and the lapse of an applicable statute of limitations.

Purchase Price Allocation

On November 1, 2010, PPL completed the acquisition of LG&E's parent. In accordance with accounting guidance on business combinations, the identifiable assets acquired and the liabilities assumed were measured at fair value at the acquisition date. Fair value is defined as the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants. The excess of the purchase price over the estimated fair value of the identifiable net assets is recorded as goodwill.

The determination and allocation of fair value to the identifiable assets acquired and liabilities assumed was based on various assumptions and valuation methodologies requiring considerable management judgment, including estimates based on key assumptions of the acquisition, and historical and current market data. The most significant variables in these valuations were the discount rates, the number of years on which to base cash flow projections, as well as the assumptions and estimates used to determine cash inflows and outflows. Although the assumptions applied were reasonable based on information available at the date of acquisition, actual results may differ from the forecasted amounts and the difference could be material.

For purposes of measuring the fair value of the majority of property, plant and equipment and regulatory assets acquired and regulatory liabilities assumed, LG&E determined that fair value was equal to net book value at the acquisition date because LG&E's operations are conducted in a regulated environment and the regulatory commissions allow for earning a rate of return on the book value of a majority of the regulated asset bases at rates determined to be fair and reasonable. As there is no current prospect for deregulation in LG&E's operating area, it is expected that these operations will remain in a regulated environment for the foreseeable future, therefore management has concluded that the use of these assets in the regulatory environment represents their highest and best use and a market participant would measure the fair value of these assets using the regulatory rate of return as the discount rate, thus resulting in fair value equal to book value.

The fair value of intangible assets and liabilities (e.g. contracts that have favorable or unfavorable terms relative to market), including coal contracts and power purchase agreements, as well as emission allowances, have been reflected on the Balance Sheets with offsetting regulatory assets or liabilities. Prior to the acquisition, LG&E recovered the cost of the coal contracts, power purchases and emission allowances and this rate treatment will continue after the acquisition. As a result, management believes the regulatory assets and liabilities created to offset the fair value adjustments meet the recognition criteria established by existing accounting guidance and eliminate any ratemaking impact of the fair value adjustments. LG&E's customer rates will continue to reflect these items (e.g. coal, purchased power, emission allowances) at their original contracted prices.

LG&E also considered whether a separate fair value should be assigned to LG&E's rights to operate within its various electric and natural gas distribution service areas but concluded that these rights only provided the opportunity to earn a regulated return and barriers to market entry, which in management's judgment is not considered a separately identifiable intangible asset under applicable accounting guidance; rather, it is considered going-concern value, or goodwill.

See Note 2, Acquisition by PPL, and Note 7, Goodwill and Intangible Assets, for further information.

New Accounting Guidance

Recent accounting pronouncements affecting LG&E are detailed in Note 1, Summary of Significant Accounting Policies.

Other Information

PPL's Audit Committee has approved the audit fees and audit-related services. The audit-related services include services in connection with regulatory filings, reviews of offering documents and registration statements and internal control reviews.

Management's Report of Internal Control Over Financial Reporting

Through December 31, 2010, the Company was 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 its internal control over financial reporting pursuant to Section 404 of the Act. However, management is responsible for establishing and maintaining adequate internal control over financial reporting. Internal control over financial reporting is a process affected b those charged with governance, management and other personnel designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with GAAP. 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 GAAP 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.

Management has assessed the effectiveness of the Company's internal control over financial reporting as of December 31, 2010 using the criteria set forth by the Committee of Sponsoring Organizations of the Treadway Commission in *Internal Control – Integrated Framework*. Management has concluded that, as of December 31, 2010, the Company's internal control over financial reporting was effective based on those criteria.

The effectiveness of the Company's internal control over financial reporting as of December 31, 2010, has been audited by PricewaterhouseCoopers LLP, an independent accounting firm, as stated in its report which is included herein.

Louisville Gas and Electric Company
Statements of Income
(millions)

	Successor	Predecessor		
	November 1, 2010 through December 31, 2010	January 1, 2010 through October 31, 2010	Year Ended December 31, 2009	Year Ended December 31, 2008
Operating revenues (Note 15):	$ 254	$ 1,057	$ 1,272	$ 1,468
Operating expenses:				
Fuel for electric generation	60	306	328	346
Power purchased (Notes 13 and 15)	10	45	59	120
Natural gas supply expenses	53	109	243	347
Other operation and maintenance expenses	68	294	339	309
Depreciation and amortization (Note 1)	23	115	136	127
Total operating expenses	214	869	1,105	1,249
Operating income	40	188	167	219
Derivative gain (loss) (Note 5)	-	19	18	(37)
Interest expense (Notes 5, 11 and 12)	7	16	17	29
Interest expense to affiliated companies (Notes 11, 12 and 15)	1	22	27	29
Other income (expense) - net	(3)	(2)	1	7
Income before income taxes	29	167	142	131
Income tax expense (Note 10)	10	58	47	41
Net income	$ 19	$ 109	$ 95	$ 90

The accompanying notes are an integral part of these financial statements.

Louisville Gas and Electric Company
Statements of Retained Earnings
(millions)

	Successor	Predecessor		
	November 1, 2010 through December 31, 2010	January 1, 2010 through October 31, 2010	Year Ended December 31, 2009	Year Ended December 31, 2008
Balance at beginning of period	$ 809	$ 755	$ 740	$ 690
Effect of PPL acquisition	(809)	-	-	-
Balance at November 1, 2010	-	755	740	690
Add net income	19	109	95	90
Cash dividends declared (Note 15)	-	55	80	40
Balance at end of period	$ 19	$ 809	$ 755	$ 740

The accompanying notes are an integral part of these financial statements.

Louisville Gas and Electric Company
Statements of Comprehensive Income
(millions)

	Successor	Predecessor		
			Year Ended December 31,	
	November 1, 2010 through December 31, 2010	January 1, 2010 through October 31, 2010	2009	2008
Net income	$ 19	$ 109	$ 95	$ 90
Gain on derivative instruments and hedging activities, net of tax benefit (expense) of $0, $(7), $(1) and $0, respectively (Note 5)	-	10	4	(2)
Comprehensive income	$ 19	$ 119	$ 99	$ 88

The accompanying notes are an integral part of these financial statements.

Louisville Gas and Electric Company
Balance Sheets
(millions)

Assets	Successor December 31, 2010	Predecessor December 31, 2009
Current assets:		
Cash and cash equivalents	$ 2	$ 5
Accounts receivable (less allowance for doubtful accounts: 2010, $2; 2009, $2):		
Customer	70	66
Affiliated companies	30	53
Other	13	12
Unbilled revenues	81	65
Available for sale debt securities	163	-
Fuel, materials and supplies:		
Fuel (predominantly coal)	68	61
Natural gas stored underground	60	56
Other materials and supplies	34	33
Other intangible assets	36	-
Regulatory assets (Note 3)	13	14
Prepayments and other current assets	13	18
Total current assets	583	383
Property, plant and equipment:		
Regulated utility plant – electric and natural gas	2,600	4,200
Accumulated depreciation	(17)	(1,708)
Net regulated utility plant	2,583	2,492
Construction work in progress	385	342
Property, plant and equipment – net	2,968	2,834
Deferred debits and other assets:		
Regulatory assets (Notes 3 and 9)		
Pension and postretirement benefits	213	204
Other regulatory assets	154	125
Goodwill (Notes 2 and 7)	389	-
Other intangible assets (Notes 2 and 7)	181	-
Other assets	31	22
Total deferred debits and other assets	968	351
Total assets	$ 4,519	$ 3,568

The accompanying notes are an integral part of these financial statements.

Louisville Gas and Electric Company
Balance Sheets (continued)
(millions)

Liabilities and Equity	Successor December 31, 2010	Predecessor December 31, 2009
Current liabilities:		
Current portion of long-term debt (Note 11)	$ -	$ 120
Notes payable to affiliated companies (Notes 12 and 15)	12	170
Note payable	163	-
Accounts payable	100	97
Accounts payable to affiliated companies (Note 15)	20	28
Accrued taxes	10	27
Customer deposits	23	22
Regulatory liabilities (Note 3)	51	38
Accrued interest	5	3
Employee accruals	17	12
Other current liabilities	16	16
Total current liabilities	417	533
Long-term debt:		
Long-term bonds (Note 11)	1,112	291
Long-term debt to affiliated company (Note 11 and 15)	-	485
Total long-term debt	1,112	776
Deferred credits and other liabilities:		
Deferred income taxes (Note 10)	419	373
Accumulated provision for pensions (Note 9)	126	198
Investment tax credits (Note 10)	46	48
Asset retirement obligations (Notes 3 and 4)	49	31
Regulatory liabilities (Note 3):		
Accumulated cost of removal of utility plant	275	259
Other regulatory liabilities	208	44
Derivative liabilities (Note 5)	32	28
Other liabilities	114	25
Total deferred credits and other liabilities	1,269	1,006

The accompanying notes are an integral part of these financial statements.

Louisville Gas and Electric Company
Balance Sheets (continued)
(millions)

	Successor December 31, 2010	Predecessor December 31, 2009
Equity:		
Common stock, without par value – authorized 75,000,000 shares, outstanding 21,294,223 shares	$ 424	$ 424
Additional paid-in capital	1,278	84
Retained earnings:		
Retained earnings	19	755
Accumulated other comprehensive loss (Note 17)	-	(10)
Total equity	1,721	1,253
Total liabilities and equity	$ 4,519	$ 3,568

The accompanying notes are an integral part of these financial statements.

Louisville Gas and Electric Company
Statements of Cash Flows
(millions)

	Successor	Predecessor		
	November 1, 2010 through December 31, 2010	January 1, 2010 through October 31, 2010	Year Ended December 31, 2009	2008
Cash flows from operating activities:				
Net income	$ 19	$ 109	$ 95	$ 90
Adjustments to reconcile net income to net cash provided by (used in) operating activities:				
Depreciation and amortization	23	115	136	127
Deferred income taxes – net	13	23	17	(5)
Investment tax credits (Note 10)	-	(2)	(2)	4
Provision for pension and postretirement benefits	6	20	33	13
Unrealized (gain) loss on derivatives	-	14	(33)	48
Regulatory asset for unrealized gain on interest rate swaps (Note 3)	-	(22)	-	-
Other – net	2	2	(3)	(7)
Change in current assets and liabilities:				
Accounts receivable	(29)	(2)	38	(3)
Unbilled revenues	(38)	22	18	(11)
Fuel, materials and supplies	10	(22)	45	(37)
Regulatory assets	2	(9)	-	-
Natural gas supply clause receivable, net	-	-	29	13
Other current assets	5	(6)	(1)	1
Accounts payable	16	-	37	(145)
Accounts payable to affiliated companies	(31)	23	(52)	144
Accrued taxes	(2)	(15)	8	18
Regulatory liabilities	1	(24)	-	-
Other current liabilities	(5)	7	(1)	(5)
Pension and postretirement benefits funding (Note 9)	(1)	(25)	(15)	(7)
Storm restoration regulatory asset (Note 3)	-	-	(44)	(24)
Other regulatory assets	1	-	-	-
Change in collateral deposit – interest rate swap	-	-	5	(10)
Other regulatory liabilities	-	(11)	-	-
Change in other comprehensive income	-	-	6	(8)
Other – net	-	(8)	(7)	1
Net cash provided by (used in) operating activities	(8)	189	309	197

The accompanying notes are an integral part of these financial statements.

Louisville Gas and Electric Company

Statements of Cash Flows (continued)

(millions)

	Successor	Predecessor		
	November 1, 2010 through December 31, 2010	January 1, 2010 through October 31, 2010	Year Ended December 31, 2009	Year Ended December 31, 2008
Cash flows from investing activities:				
Construction expenditures	$ (65)	$ (155)	$ (186)	$ (243)
Proceeds from sale of assets to affiliated company	-	48	-	10
Proceeds from sale of assets	-	-	3	9
Change in restricted cash	2	-	-	-
Cash settlement on derivatives	-	-	7	(8)
Net cash provided by (used in) investing activities	(63)	(107)	(176)	(232)
Cash flows from financing activities:				
Issuance of bonds (Note 11)	531	-	-	-
Issuance of short-term note payable (Note 12)	163	-	-	-
Short-term borrowings from affiliated company – net (Note 12)	(130)	(28)	(52)	144
Other borrowings from affiliated companies (Note 11)	485	-	-	75
Repayments on other borrowings to affiliated companies (Note 11)	(485)	-	-	-
Repayments to E.ON affiliate (Note 11)	(485)	-	-	-
Debt issuance costs	(10)	-	-	-
Acquisition of outstanding bonds	-	-	-	(259)
Reissuance of reacquired bonds	-	-	-	95
Payment of dividends	-	(55)	(80)	(40)
Capital contribution (Note 15)	-	-	-	20
Net cash provided by (used in) financing activities	69	(83)	(132)	35
Change in cash and cash equivalents	(2)	(1)	1	-
Cash and cash equivalents at beginning of period	4	5	4	4
Cash and cash equivalents at end of period	$ 2	$ 4	$ 5	$ 4

The accompanying notes are an integral part of these financial statements.

Louisville Gas and Electric Company
Statements of Cash Flows (continued)
(millions)

	Successor	Predecessor		
	November 1, 2010 through December 31, 2010	January 1, 2010 through October 31, 2010	Year Ended December 31, 2009	Year Ended December 31, 2008
Supplemental disclosures of cash flow information:				
Cash paid (received) during the year for:				
Interest – net of amount capitalized	$ 11	$ 39	$ 36	$ 38
Income taxes – net................................	(8)	60	23	24

The accompanying notes are an integral part of these financial statements.

Louisville Gas and Electric Company
Statements of Capitalization
(millions)

	Successor December 31, 2010	Predecessor December 31, 2009
Long-term debt (Note 11):		
Pollution control series:		
Jefferson Co. 2001 Series A, due September 1, 2026, variable %	$ 22	$ 22
Trimble Co. 2001 Series A, due September 1, 2026, variable %	28	28
Jefferson Co. 2000 Series A, due May 1, 2027, 5.375%	25	25
Jefferson Co. 2001 Series A, due September 1, 2027, variable %	10	10
Jefferson Co. 2001 Series B, due November 1, 2027, variable %	35	35
Trimble Co. 2001 Series B, due November 1, 2027, variable %	35	35
Trimble Co. 2000 Series A, due August 1, 2030, variable %	83	83
Trimble Co. 2002 Series A, due October 1, 2032, variable %	42	42
Trimble Co. 2007 Series A, due June 1, 2033, 4.60%	60	60
Louisville Metro 2007 Series A, due June 1, 2033, 5.625%	31	31
Louisville Metro 2007 Series B, due June 1, 2033, variable %	35	35
Louisville Metro 2003 Series A, due October 1, 2033, variable %	128	128
Louisville Metro 2005 Series A, due February 1, 2035, 5.75%	40	40
Total pollution control series	574	574
First mortgage bonds:		
First mortgage bond 2015 Series, due November 15, 2015, 1.625%	250	-
First mortgage bond 2040 Series, due November 15, 2040, 5.125%	285	-
Total first mortgage bonds	535	-
Notes payable to Fidelia:		
Due January 16, 2012, 4.33%, unsecured	-	25
Due April 30, 2013, 4.55%, unsecured	-	100
Due August 15, 2013, 5.31%, unsecured	-	100
Due November 23, 2015, 6.48%, unsecured	-	50
Due July 25, 2018, 6.21%, unsecured	-	25
Due November 26, 2022, 5.72%, unsecured	-	47
Due April 13, 2031, 5.93%, unsecured	-	68
Due April 13, 2037, 5.98 %, unsecured	-	70
Total notes payable to Fidelia	-	485
Total long-term debt outstanding	1,109	1,059

The accompanying notes are an integral part of these financial statements.

Louisville Gas and Electric Company
Statements of Capitalization (continued)
(millions)

	Successor December 31, 2010	Predecessor December 31, 2009
Total long-term debt outstanding	$ 1,109	$ 1,059
Less reacquired debt	-	163
Purchase-accounting adjustments and discounts (net)	3	-
Less current portion of long-term debt	-	120
Long-term debt	1,112	776
Common equity:		
Common stock, without par value -		
Authorized 75,000,000 shares, outstanding 21,294,223 shares	424	424
Additional paid-in capital	1,278	84
Accumulated other comprehensive loss (Note 17)	-	(10)
Retained earnings	19	755
Total common equity	1,721	1,253
Total capitalization	$ 2,833	$ 2,029

The accompanying notes are an integral part of these financial statements.

Louisville Gas and Electric Company
Notes to Financial Statements

Note 1 - Summary of Significant Accounting Policies

General

Terms and abbreviations are explained in the index of abbreviations. Dollars are in millions unless otherwise noted.

Business

LG&E, incorporated in Kentucky in 1913, is a regulated utility engaged in the generation, transmission, distribution and sale of electric energy and the storage, distribution and sale of natural gas. LG&E provides electric service to approximately 395,000 customers in Louisville and adjacent areas in Kentucky covering approximately 700 square miles in nine counties. Natural gas service is provided to approximately 320,000 customers in its electric service area and eight additional counties in Kentucky. Approximately 95% of the electricity generated by LG&E is produced by its coal-fired electric generating stations, all equipped with systems to reduce SO_2 emissions. The remainder is generated by natural gas and oil fueled CTs and a hydroelectric power plant. Underground natural gas storage fields help the Company provide economical and reliable natural gas service to customers.

On November 1, 2010, LG&E became an indirect wholly owned subsidiary of PPL, when PPL acquired all of the outstanding limited liability company interests in the Company's direct parent, LKE, from E.ON US Investments Corp. LKE, a Kentucky limited liability company, also owns the affiliate, KU, a regulated utility engaged in the generation, transmission, distribution and sale of electric energy in Kentucky, Virginia and Tennessee. Following the acquisition, the Company's business has not changed. LG&E and KU are continuing as subsidiaries of LKE, which is now an intermediary holding company in the PPL group of companies.

Headquartered in Allentown, Pennsylvania, PPL is an energy and utility holding company that was incorporated in 1994. Through its subsidiaries, PPL owns or controls about 19,000 megawatts of generating capacity in the U.S., sells energy in key U.S. markets and delivers electricity and natural gas to about 5.3 million customers in the U.S. and the U.K.

Basis of Accounting

LG&E's basis of accounting incorporates the business combinations guidance of the FASB ASC as of the date of the acquisition, which requires the recognition and measurement of identifiable assets acquired and liabilities assumed at fair value as of the acquisition date. LG&E's financial statements and accompanying footnotes have been segregated to present pre-acquisition activity as the Predecessor and post-acquisition activity as the Successor. Predecessor covers the time period prior to November 1, 2010. Successor covers the time period after October 31, 2010. Certain accounting and presentation methods were changed to acceptable alternatives to conform to PPL accounting policies, which are discussed below, and the cost basis of certain assets and liabilities were changed as of November 1, 2010, as a result of the application of push-down accounting. Consequently, the financial position, results of operations and cash flows for the Predecessor period are not comparable to the Successor period.

Despite the separate presentation, the core operations of the Company have not changed. See Note 2, Acquisition by PPL, for information regarding the acquisition and the purchase accounting adjustments.

Changes in Classification

Certain reclassification entries have been made to the Predecessor's previous years' financial statements to conform to the 2010 presentation with no impact on total assets, liabilities and capitalization or previously reported net income and cash flows. These reclassifications mainly consist of those necessary to identify amounts for prior periods that are separately disclosed in the financial statements.

Regulatory Accounting

LG&E is a cost-based rate-regulated utility. As a result, the financial statements reflect the effects of regulatory actions. Regulatory assets are recognized for the effect of transactions or events where future recovery is probable in regulated customer rates. The effect of such accounting is to defer certain or qualifying costs that would otherwise be charged to expense. Likewise, regulatory liabilities may be recognized for obligations expected to be returned through future regulated customer rates. The effect of such transactions or events would otherwise be reflected as income, or, in certain cases, regulatory liabilities are recorded based on the understanding with the regulator that current rates are being set to recover costs that are expected to be incurred in the future. The regulated entity is accountable for any amounts charged pursuant to such rates and not yet expended for the intended purpose. Offsetting regulatory assets or liabilities for fair value purchase accounting adjustments have also been recorded to eliminate any ratemaking impact of the fair value adjustments. The accounting for regulatory assets and liabilities is based on specific ratemaking decisions or precedent for each transaction or event as prescribed by the FERC or the Kentucky Commission. See Note 3, Rates and Regulatory Matters, for additional detail regarding regulatory assets and liabilities.

Management's Use of Estimates

The preparation of financial statements in conformity with GAAP requires management to make estimates and assumptions that affect the reported assets and liabilities, the disclosure of contingent liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. Actual results could differ from those estimates.

Derivative Financial Instruments

LG&E enters into interest rate swap contracts to hedge exposure to variability in expected cash flows associated with existing debt instruments. LG&E enters into energy trading contracts to manage price risk and to maximize the value of power sales from the physical assets it owns.

Interest rate swap contracts and energy trading contracts meet the definition of a derivative and are reflected on the Balance Sheets at fair value in accordance with the derivatives and hedging guidance of the FASB ASC. Beginning in the third quarter of 2010, the change in fair value of interest rate swap contracts is recorded as regulatory assets or liabilities based on an Order from the Kentucky Commission in the 2010 rate case whereby the cost of a terminated swap was allowed to be recovered in base rates. Prior to the third quarter, interest rate swaps designated as effective cash flow hedges had resulting gains and losses recorded within other comprehensive income and common equity. The ineffective portion of interest rate swaps designated as cash flow hedges was previously recorded to earnings monthly, as was the entire change in the market value of the ineffective swaps. The energy trading contracts are non-hedging derivatives and the change in value is recognized in earnings on a mark-to-market basis.

Interest rate swap contracts are recorded by the Successor as "Other current liabilities" or non-current "Derivative liabilities" on the Balance Sheets. The current and non-current interest rate swap liabilities are calculated by dividing the total interest rate swap liability by the number of years remaining on the contract at the end of the period. The Predecessor classified all interest rate swap liabilities as non-current "Derivative liabilities" on the Balance Sheets. The Successor and Predecessor presentation are both appropriate under GAAP. The Predecessor and Successor determine the classification of energy trading contracts based on the settlement date of the individual contracts. Energy trading contracts classified as current are recognized in "Prepayments and other current assets" or "Other current liabilities" on the Balance Sheets. Energy trading contracts classified as non-current are recognized in "Other assets" or long-term "Derivative liabilities" on the Balance Sheets. Cash inflows and outflows related to derivative instruments are included as a component of operating activity on the Statements of Cash Flows due to the underlying nature of the hedged items.

The Company does not net collateral against derivative instruments.

See Note 5, Derivative Financial Instruments, and Note 6, Fair Value Measurements, for further information on derivative instruments.

Revenue and Accounts Receivable

The operating revenues line item in the Statements of Income contains revenues from the following:

	Successor	Predecessor		
	November 1, 2010 through December 31, 2010	January 1, 2010 through October 31, 2010	Year Ended December 31,	
			2009	2008
Residential	$ 113	$ 446	$ 540	$ 582
Industrial and commercial	92	409	475	523
Other retail	22	98	109	105
Wholesale	27	104	148	258
	$ 254	$ 1,057	$ 1,272	$ 1,468

Revenue Recognition

Revenues are recorded based on service rendered to customers through month-end. Operating revenues are recorded based on energy deliveries through the end of the calendar month. Unbilled retail revenues result because customers' meters are read and bills are rendered throughout the month, rather than all being read at the end of the month. Unbilled revenues for a month are calculated by multiplying an estimate of unbilled kWh by the estimated average cents per kWh.

Accounts Receivable

Accounts receivable are reported in the Balance Sheets at the gross outstanding amount adjusted for an allowance for doubtful accounts.

Allowance for Doubtful Accounts

The allowance for doubtful accounts included in "Accounts receivable – customer" 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. The allowance for doubtful accounts included in "Accounts receivable – other" is composed of accounts aged more than four months. Accounts are written off as management determines them uncollectible.

The changes in the allowance for doubtful accounts were:

	Successor	Predecessor		
	December 31, 2010	October 31, 2010	December 31, 2009	December 31, 2008
Balance at beginning of period (a)	$ -	$ 2	$ 2	$ 2
Charged to income	1	(4)	(4)	(2)
Charged to balance sheets	1	4	4	2
Balance at end of period	$ 2	$ 2	$ 2	$ 2

(a) Successor beginning of period reflects revaluation of accounts receivable due to purchase accounting.

Cash

Cash Equivalents

All highly liquid investments with an original maturity of three months or less are considered to be cash equivalents.

Restricted Cash

Bank deposits and other cash equivalents that are restricted by agreement or that have been clearly designated for a specific purpose are classified as restricted cash. The change in restricted cash is reported as an investing activity on the Statements of Cash Flows. On the Balance Sheets, the current portion of restricted cash is included in "Prepayments and other current assets," and the non-current portion is included in "Other assets." For LG&E, the December 31, 2010, balance of restricted cash is $22 million, consisting primarily of cash collateral posted to counterparties related to LG&E's interest rate swap contracts.

Fair Value Measurements

LG&E values certain financial assets and liabilities at fair value. Generally, the most significant fair value measurements relate to derivative assets and liabilities, investments in securities including investments in the pension and postretirement benefit plans and reacquired bonds and cash and cash equivalents. LG&E uses, as appropriate, a market approach (generally, data from market transactions), an income approach (generally, present value techniques) and/or a cost approach (generally, replacement cost) to measure the fair value of an asset or liability. These valuation approaches incorporate inputs such as observable, independent market data and/or unobservable data that management believes are predicated on the assumptions that market participants would use to price an asset or liability. These inputs may incorporate, as applicable, certain risks such as nonperformance risk, which includes credit risk.

LG&E prioritizes fair value measurements for disclosure by grouping them into one of three levels in the fair value hierarchy. The highest priority is given to measurements using level 1 inputs. The appropriate level assigned to a fair value measurement is based on the lowest level input that is significant to the fair value measurement in its entirety. The three levels of the fair value hierarchy are as follows:

- Level 1 - Observable inputs that reflect quoted prices (unadjusted) for identical assets or liabilities in active markets.
- Level 2 - Other inputs that are directly or indirectly observable in the marketplace.
- Level 3 - Unobservable inputs which are supported by little or no market activity.

Assessing the significance of a particular input requires judgment that considers factors specific to the asset or liability. As such, LG&E's assessment of the significance of a particular input may affect how the assets and liabilities are classified within the fair value hierarchy. See Note 5, Derivative Financial Instruments, and Note 6, Fair Value Measurements, for further information on fair value measurements.

Investments

Investments in Debt Securities

At December 31, 2010, LG&E had $163 million of bonds classified as "Long- term debt" on the Balance Sheets that LG&E reacquired. The Successor has classified these bonds as "Available for sale debt securities" because management intended to remarket the bonds at a later date. The Predecessor classified the reacquired bonds as an offset to "Long-term debt" because the Company was no longer obligated to any third party investors. The Predecessor presentation and the Successor presentation are both appropriate under GAAP.

"Available for sale debt securities" are carried at fair value and are classified as current assets on the Balance Sheets. Unrealized gains and losses on all available for sale debt securities are reported, net of tax, in other comprehensive income or recognized in earnings when the decline in fair value below cost is determined to be other-than-temporary impairment. For 2010, LG&E had no unrealized gains or losses on available for sale debt securities.

The criteria for determining whether a decline in fair value of a debt security is other than temporary and whether the other-than-temporary impairment is recognized in earnings or reported in other comprehensive income when the debt security is in an unrealized position is as follows:

- if there is intent to sell the security or a requirement to sell the security before recovery, the other-than-temporary impairment is recognized currently in earnings; or
- if there is no intent to sell the security or requirement to sell the security before recovery, the portion of the other-than-temporary impairment that is considered a credit loss is recognized currently in earnings and the remainder of the other-than-temporary impairment is reported in other comprehensive income, net of tax; or
- if there is no intent to sell the security or requirement to sell the security before recovery and there is no credit loss, the unrealized loss is reported in other comprehensive income, net of tax.

See Note 19, Subsequent Events, for the current status of reacquired bonds.

Cost Method Investment

LG&E's cost method investment, included in "Other assets" on the Balance Sheets, consists of the Company's investment in OVEC. LG&E and 11 other electric utilities are owners of OVEC, which is located in Piketon, Ohio. OVEC owns and operates two coal-fired power plants, Kyger Creek Station in Ohio and Clifty Creek Station in Indiana with combined nameplate generating capacities of 2,390 Mw. OVEC's power is currently supplied to LG&E and 13 other companies affiliated with the various owners. Pursuant to current contractual agreements, LG&E owns 5.63% of OVEC's common stock and is contractually entitled to 5.63% of OVEC's output. Based on nameplate generating capacity, this would be approximately 134 Mw.

As of December 31, 2010 and 2009, LG&E's investment in OVEC totaled less than $1 million. LG&E is not the primary beneficiary of OVEC; therefore, it is not consolidated into the Company's financial statements and is accounted for under the cost method of accounting. The direct exposure to loss as a result of the Company's involvement with OVEC is generally limited to the value of its investment; however, LG&E may be conditionally responsible for a pro-rata share of certain OVEC obligations. See Note 2, Acquisition by PPL, and Note 13, Commitments and Contingencies, for further discussion regarding purchase accounting adjustments recognized, ownership interest and power purchase rights.

Long-Lived and Intangible Assets

Regulated Utility Plant

Regulated utility plant was stated at original cost for the Predecessor and adjusted to the net book value on November 1, 2010, the acquisition date for the Successor. LG&E determined that fair value was equal to net book value at the acquisition date since LG&E's operations are conducted in a regulated environment. Original cost 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. LG&E has not recorded any allowance for funds used during construction in accordance with the FERC.

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.

Capitalized Software Cost

Included in "Property, plant and equipment" on the Balance Sheets are capitalized costs of software projects that were developed or obtained for internal use. These capitalized costs are amortized ratably over the expected lives of the projects when they become operational, generally not to exceed five years. Following are capitalized software costs and the accumulated amortization:

Successor		Predecessor	
December 31, 2010		December 31, 2009	
Carrying Amount	Accumulated Amortization (a)	Carrying Amount	Accumulated Amortization
$ 44	$ 1	$ 63	$ 18

(a) The accumulated amortization as of November 1, 2010, was netted against the carrying amount of the software as the fair value was determined to be equal to net book value for property, plant and equipment.

Amortization expense of capitalized software costs was as follows:

Successor	Predecessor		
November 1, 2010 through December 31, 2010	January 1, 2010 through October 31, 2010	Year Ended December 31,	
		2009	2008
$ 1	$ 7	$ 8	$ 6

The amortization of capitalized software is included in "Depreciation and amortization" on the Statements of Income.

Depreciation and Amortization

Depreciation is provided on the straight-line method over the estimated service lives of depreciable plant. The amounts provided as a percentage of depreciable plant were approximately:

Year	Average Percentage
2010	5.4%
2009	3.1%
2008	3.2%

Of the amount provided for depreciation, the following were related to the retirement, removal and disposal costs of long lived assets:

Year	Average Percentage
2010	0.9%
2009	0.5%
2008	0.4%

Goodwill, Intangible Assets and Asset Impairment

LG&E performs a quarterly review to determine if an impairment analyses is required for long-lived assets that are subject to depreciation or amortization. This review identifies changes in circumstances indicating that a long-lived asset's carrying value may not be recoverable. An impairment analysis will be performed if warranted, based on the review.

For a long-lived asset to be held and used, impairment exists when the carrying amount exceeds the sum of the undiscounted cash flows expected to result from the use and eventual disposition of the asset. If the asset is impaired, an impairment loss is recorded to adjust the asset's carrying amount to its fair value.

LG&E, as the result of PPL's acquisition of LKE, recorded the fair value of its coal contracts, emission allowances and OVEC power purchase contract. The difference between the fair value and the cost for these assets is being amortized over their useful lives based upon the pattern in which the economic benefits of the intangible assets are consumed or otherwise used. When determining the useful life of an intangible asset, including intangible assets that are renewed or extended, LG&E considers the expected use of the asset, the expected useful life of other assets to which the useful life of the intangible asset may relate and legal, regulatory, or contractual provisions that may limit the useful life. See Note 2, Acquisition by PPL, for methods used to determine the long-lived intangible assets' fair values. See Note 7, Goodwill and Intangible Assets, for the fair value amounts and amortization periods. The current intangible assets and long-term intangible assets are included in "Other intangible assets" on the Balance Sheets.

The Predecessor reported emission allowances in "Other materials and supplies" on the Balance Sheets. The emission allowances were not amortized; rather, they were expensed when consumed. The Predecessor did not recognize the coal contracts or the OVEC power purchase contract, as these intangible assets were not derivatives.

In connection with PPL's acquisition of LKE, LG&E recorded goodwill on November 1, 2010. Goodwill represents the excess of the purchase price paid over the estimated fair value of the assets acquired and liabilities assumed in the acquisition of a business. Goodwill is tested annually for impairment during the fourth quarter, or more frequently if management determines that a triggering event may have occurred that would more likely than not reduce the fair value of an operating unit below its carrying value. Goodwill impairment charges are not subject to rate recovery. See Note 7, Goodwill and Intangible Assets, for further discussion regarding the Company's goodwill and current test results.

Asset Retirement Obligations

LG&E recognizes various legal obligations associated with the retirement of long-lived assets as liabilities in the financial statements. Initially this obligation is measured at fair value. An equivalent amount is recorded as an increase in the value of the capitalized asset and allocated to expense over the useful life of the asset. Until the obligation is settled, the liability is increased, through the recognition of accretion expense in the Statements of Income, for changes in the obligation due to the passage of time. An offsetting regulatory asset is recognized to reverse the depreciation and accretion expense related to the ARO such that there is no income statement impact. The regulatory asset is relieved when the ARO has been settled. Estimated ARO costs and settlement dates, which affect the carrying value of various AROs and the related assets, are reviewed periodically to ensure that any material changes are incorporated into the latest estimate of the obligations. See Note 4, Asset Retirement Obligations, for further information on AROs.

Defined Benefits

LG&E employees benefit from both funded and unfunded retirement benefit plans . An asset or liability is recorded to recognize the funded status of all defined benefit plans with an offsetting entry to regulatory assets or regulatory liabilities. Consequently, the funded status of all defined benefit plans is fully recognized on the Balance Sheets.

The expected return on plan assets is determined based on the current level of expected return 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 is then weighted based on the current asset allocation.

The discount rate used for pensions, postretirement and post-employment plans by the Predecessor was determined using the Mercer Yield Curve. The expected return on assets assumption was 7.75%. Gains and losses in excess of 10% of the greater of the plan's projected benefit obligation or market value of assets were amortized on a straight-line basis over the average future service period of active participants. The market-related value of assets was equal to the fair market value of the assets.

The discount rate used by the Successor was determined by the Towers Watson Yield Curve based on the individual plan cash flows. The expected return on assets was reduced from 7.75% to 7.25%. The amortization period for the recognition of gains and losses for retirement plans was changed to reflect the Successor's amortization policy. Under the Successor's method, gains and losses in excess of 10% but less than 30% of the greater of the plan's projected benefit obligation or market-related value of assets, are amortized on a straight-line basis over the average future service period of active participants. Gains and losses in excess of 30% of the plan's projected benefit obligation or market-related value of assets are amortized on a straight-line basis over a period equal to one-half of the average future service period of active participants. The market-related value of assets for the qualified retirement plans will be equal to a five year smoothed asset value. Gains and losses in excess of the expected return will be phased-in over a five year period, prospectively from November 1, 2010.

See Note 9, Pension and Other Postretirement Benefit Plans, for further information.

Other

Loss Accruals

Potential losses are accrued when information is available that indicates it is "probable" that a loss has been incurred, given the likelihood of uncertain future events, and the amount of the loss can be reasonably estimated. Accounting guidance defines "probable" as cases in which "the future event or events are likely to occur." LG&E continuously assesses potential loss contingencies for environmental remediation, litigation claims, regulatory penalties and other events.

LG&E does not record the accrual of contingencies that might result in gains unless recovery is assured.

Income Taxes

For the periods ended on or before October 31, 2010, LG&E was a subsidiary of E.ON U.S. and was part of E. ON U.S.'s direct parent's, E.ON US Investments Corp., consolidated U.S. federal income tax return. On November 1, 2010, LG&E became a part of PPL's consolidated U.S. federal income tax return.

Significant management judgment is required in developing LG&E's provision for income taxes primarily due to the uncertainty related to tax positions taken or expected to be taken in tax returns and the determination of deferred tax assets, liabilities and valuation allowances.

LG&E evaluates tax positions following a two-step process. The first step requires an entity to determine whether, based on the technical merits supporting a particular tax position, it is more likely than not (greater than a 50% chance) that the tax position will be sustained. This determination assumes that the relevant taxing authority will examine the tax position and is aware of all the relevant facts surrounding the tax position. The second step requires an entity to recognize in the financial statements the benefit of a tax position that meets the more-likely-than-not recognition criterion. The benefit recognized is measured at the largest amount of benefit that has a likelihood of realization, upon settlement, that exceeds 50%. The amounts ultimately paid upon resolution of issues raised by taxing authorities may differ materially from the amounts accrued and may materially impact the financial statements of LG&E.

Deferred income taxes reflect the net future tax effects of temporary differences between the carrying amounts of assets and liabilities for accounting purposes and their basis for income tax purposes, as well as the tax effects of net operating losses and tax credit carryforwards.

LG&E records valuation allowances to reduce deferred tax assets to the amounts that are more likely than not to be realized. LG&E considers the reversal of temporary differences, future taxable income and ongoing prudent and feasible tax planning strategies in initially recording and subsequently reevaluating the need for valuation allowances. If LG&E determines that it is able to realize deferred tax assets in the future in excess of recorded net deferred tax assets, adjustments to the valuation allowances increase income by reducing tax expense in the period that such determination is made. Likewise, if LG&E determines that it is not able to realize all or part of net deferred tax assets in the future, adjustments to the valuation allowances would decrease income by increasing tax expense in the period that such determination is made.

The provision for LG&E's deferred income taxes for regulated assets and liabilities is based upon the ratemaking principles reflected in rates established by the regulators. The difference in the provision for deferred income taxes for regulated assets and liabilities and the amount that otherwise would be recorded under GAAP is deferred and included on the Balance Sheets in "Regulatory liabilities."

LG&E defers investment tax credits when the credits are utilized and amortizes the deferred amounts over the average lives of the related assets.

See Note 10, Income Taxes, for further discussion regarding income taxes.

Leases

LG&E evaluates whether arrangements entered into contain leases for accounting purposes.

Materials and Supplies

Fuel, natural gas stored underground and other materials and supplies inventories are accounted for using the average-cost method.

Fuel and Natural Gas Costs

The cost of fuel for electric generation is charged to expense as used and the cost of natural gas supply is charged to expense as delivered to the distribution system. LG&E operates under a Kentucky Commission approved PBR mechanism related to natural gas procurement activity. See Note 3, Rates and Regulatory Matters, for a description of the FAC and GSC.

Debt

The Company's long-term debt includes $120 million of pollution control bonds, which are subject to tender for purchase at the option of the holder and to mandatory tender for purchase on the occurrence of certain events. The Successor has classified these bonds as long term because the Company has the intent and ability to utilize its $400 million credit facility, which matures in December 2014, to fund any mandatory purchases. Predecessor classified these bonds as the current portion of long-term debt due to the tender for purchase provisions. The Predecessor presentation and the Successor presentation are both appropriate under GAAP. See Note 11, Long-Term Debt, and Note 12, Notes Payable and Other Short-Term Obligations, for more information on the Company's debt and credit facilities.

Unamortized Debt Expense

Debt expense is capitalized and amortized over the lives of the related bond issues using the straight-line method, which approximates the effective interest method. Depending on the type of expense, the Successor capitalized debt expenses in long-term other regulatory assets or long-term other assets to align with the term of the debt the expenses were related. The Predecessor capitalized debt expenses in current or long-term other regulatory assets or other current or long-term other assets based on the amount of expense expected to be recovered within the next year through rate recovery. Both the Predecessor and the Successor amortize debt expenses over the lives of the related bond issues. The Predecessor presentation and the Successor presentation are both appropriate under regulatory practices and GAAP.

Recent Accounting Pronouncements

The following recent accounting pronouncement affected LG&E:

Fair Value Measurements

In January 2010, the FASB issued guidance related to fair value measurement disclosures requiring separate disclosure of amounts of significant transfers in and out of level 1 and level 2 fair value measurements and separate information about purchases, sales, issuances and settlements within level 3 measurements. This guidance is effective for the interim and annual reporting periods beginning after December 15, 2009, except for the disclosures about the roll-forward of activity in level 3 fair value measurements. Those disclosures are effective for fiscal years beginning after December 15, 2010 and for interim periods within those fiscal years. This guidance has no impact on the Company's results of operations, financial position, liquidity or disclosures.

Note 2 - Acquisition by PPL

On November 1, 2010, PPL completed its acquisition of LKE and its subsidiaries. The push-down basis of accounting was used to record the fair value adjustments of assets and liabilities on LKE at the acquisition date. PPL paid a cash consideration for LKE and its subsidiaries of $2,493 million as well as a capital contribution on November 1, 2010, of $1,565 million; included within this was the consideration paid for LG&E of $1,702 million. The allocation of the LG&E purchase price was based on the fair value of assets acquired and liabilities assumed.

The allocation of the purchase price to the fair value of assets acquired and liabilities assumed is as follows:

Current assets	$	546
Investments		1
Property, plant and equipment		2,935
Other intangible assets		183
Regulatory and other non-current assets		416
Current liabilities		(420)
Affiliated debt		(485)
Debt		(580)
Other non-current liabilities		(1,283)
Net identifiable assets acquired		1,313
Goodwill		389
Total purchase price	$	1,702

Goodwill represents value paid for the rate regulated business of LG&E, which is located in a defined service area with a constructive regulatory environment, which provides for future investment, earnings and cash flow growth, as well as the talented and experienced workforce. LG&E's franchise values are being attributed to the going concern value of the business, and thus were recorded as goodwill rather than a separately identifiable intangible asset. None of the goodwill recognized is deductible for income tax purposes or included in regulated customer rates.

Adjustments to LG&E's assets and liabilities that contributed to goodwill were as follows:

The pollution control bonds, excluding the reacquired bonds, had a fair market value adjustment of $7 million. All variable bonds were valued at par while the fixed rate bonds were valued with a yield curve based on average credit spreads for similar bonds.

As a result of the purchase accounting associated with the acquisition, the following items had a fair value adjustment but no effect on goodwill as the offset was either a regulatory asset or liability. The regulatory asset or liability has been recorded to eliminate any ratemaking impact of the fair value adjustments:

- The value of OVEC was determined to be $87 million based upon an announced transaction by another owner. LG&E's stock was valued at less than $1 million and the power purchase agreement has been valued at $87 million. An intangible asset was recorded with the offset to regulatory liability and will be amortized using the units of production method until the power purchase agreement ends in March 2026 .
- LG&E recorded an emission allowance intangible asset and regulatory liability as the result of adjusting the fair value of the emission allowance at LG&E. The emission allowance intangible of $8 million represents allocated and purchased SO_2 and NOx emission allowances that are unused as of the valuation date or allocated for use in future years. LG&E had previously recorded emission allowances as other materials and supplies. To conform to PPL's accounting policy all emission allowances are now recorded as intangible assets. This emission allowance intangible asset is amortized as the emission allowances are consumed, which is expected to occur through 2040.
- LG&E recorded a coal contract intangible asset of $124 million and a non-current liability of $11 million on the Balance Sheets. An offsetting regulatory asset was recorded for those contracts with unfavorable terms relative to market. An offsetting regulatory liability was recorded for those contracts that had favorable terms relative to market. All coal contracts held by LG&E, wherein it had entered into arrangements to buy amounts of coal at fixed prices from counterparties at a future date, were fair valued. The intangible assets and other liabilities, as well as the regulatory assets and liabilities, are being amortized over the same terms as the related contracts, which expire through 2016.

The fair value of intangible assets and liabilities (e.g. contracts that have favorable or unfavorable terms relative to market), including coal contracts and power purchase agreements, as well as emission allowances, have been reflected on the Balance Sheets with offsetting regulatory assets or liabilities. Prior to the acquisition, LG&E recovered the cost of the coal contracts, power purchases and emission allowances and this rate treatment will continue after the acquisition. As a result, management believes the regulatory assets and liabilities created to offset the fair value adjustments meet the recognition criteria established by existing accounting guidance and eliminate any ratemaking impact of the fair value adjustments. LG&E's customer rates will continue to reflect these items (e.g. coal, purchased power, emission allowances) at their original contracted prices.

LG&E also considered whether a separate fair value should be assigned to LG&E's rights to operate within its various electric and natural gas distribution service areas but concluded that these rights only provided the opportunity to earn a regulated return and barriers to market entry, which in management's judgment is not considered a separately identifiable intangible asset under applicable accounting guidance; rather, it is considered going-concern value, or goodwill.

Note 3 - Rates and Regulatory Matters

The Company is subject to the jurisdiction of the FERC and Kentucky Commission in virtually all matters related to electric and natural gas utility regulation and as such, its accounting is subject to the regulated operations guidance of the FASB ASC. Given its position in the marketplace and the status of regulation in Kentucky, there are no plans or intentions to discontinue the application of the regulated operations guidance of the FASB ASC.

LG&E's base rates are calculated based on a return on capitalization (common equity, long-term debt and notes payable) including certain regulatory adjustments to exclude non-regulated investments and environmental compliance plans recovered separately through the ECR mechanism. No regulatory assets or regulatory liabilities recorded at the time base rates were determined were excluded from the return on capitalization utilized in the calculation of Kentucky base rates. Therefore, a return is earned on all Kentucky regulatory assets existing at the time base rates were determined, except where such regulatory assets were offset by associated liabilities and thus, have no net impact on capitalization.

As a result of purchase accounting, certain fair value amounts, reflecting contracts that have favorable or unfavorable terms relative to market, were recorded on the Balance Sheets with offsetting regulatory assets or liabilities. Prior to the acquisition, LG&E recovered in customer rates the cost of the coal contracts, power purchases and emission allowances and this rate treatment will continue after the recognition criteria established by existing accounting guidance and eliminate any ratemaking impact of the fair value adjustments. LG&E's customer rates will continue to reflect these items (e.g. coal, purchased power, emission allowances) at their original contracted prices.

<u>2010 Purchase and Sale Agreement with PPL</u>

On April 28, 2010, E.ON U.S. announced that a Purchase and Sale Agreement (the "Agreement") had been entered into among E.ON US Investments Corp., PPL and E.ON.

The transaction was subject to customary closing conditions, including the expiration or termination of the applicable waiting period under the Hart-Scott-Rodino Act, receipt of required regulatory approvals (including state regulators in Kentucky and the FERC) and the absence of injunctions or restraints imposed by governmental entities.

Change of control and financing-related applications were filed on May 28, 2010 with the Kentucky Commission. An application with the FERC was filed on June 28, 2010. During the second quarter of 2010, a number of parties were granted intervenor status in the Kentucky Commission proceedings and data request filings and responses occurred. Early termination of the Hart-Scott-Rodino waiting period was received on August 2, 2010.

A hearing in the Kentucky Commission proceedings was held on September 8, 2010 at which time a unanimous settlement agreement was presented. In the settlement, LG&E committed that no base rate increases would take effect before January 1, 2013. The LG&E rate increases that took effect on August 1, 2010, were not impacted by the settlement. Under the terms of the settlement, LG&E retains the right to seek approval for the deferral of "extraordinary and uncontrollable costs." Interim rate adjustments will continue to be permissible during that period for existing fuel, environmental and demand-side management cost trackers. The agreement also substitutes an acquisition savings shared deferral mechanism for the requirement that the Utilities file a synergies plan with the Kentucky Commission. This mechanism, which will be in place until the earlier of five years or the first day of the year in which a base rate increase becomes effective, permits LG&E to earn up to a 10.75% return on equity. Any earnings above a 10.75% return on equity will be shared with customers on a 50%/50% basis. On September 30, 2010, the Kentucky Commission issued an Order approving the transfer of ownership of LG&E via the acquisition of E.ON U.S. by PPL, incorporating the terms of the submitted settlement. The Commission's Orders contained a number of other commitments with regard to operations, workforce, community involvement and other matters.

In mid-September 2010, LG&E and other applicants in the FERC change of control proceeding reached an agreement with the protesters, whereby such protests were withdrawn. The agreement, which was filed for consideration with the FERC, includes various conditional commitments, such as a continuation of certain existing undertakings with protesters in prior cases, an exclusion of any transaction-related costs from wholesale energy and tariff customer rates to the extent that LG&E agreed not to seek the same transaction-related cost from retail customers and agreements to coordinate with protesters in certain open or ongoing matters. A FERC Order approving the transaction was received on October 26, 2010 and the transaction was completed November 1, 2010.

2010 Kentucky Rate Case

In January 2010, LG&E filed an application with the Kentucky Commission requesting an increase in electric base rates of approximately 12%, or $95 million annually, and its natural gas base rates of approximately 8%, or $23 million annually. In June 2010, LG&E and all of the intervenors, except the AG, agreed to stipulations providing for increases in electric base rates of $74 million annually and natural gas base rates of $17 million annually and filed a request with the Kentucky Commission to approve such settlement. An Order in the proceeding was issued in July 2010, approving all the provisions in the stipulations, including a return on equity range of 9.75%-10.75%. The new rates became effective on August 1, 2010.

2008 Kentucky Rate Case

In July 2008, LG&E filed an application with the Kentucky Commission requesting increases in electric and natural gas base rates. In January 2009, LG&E, the AG, the KIUC and all other parties to the rate cases filed a settlement agreement with the Kentucky Commission, under which LG&E's natural gas base rates increased by $22 million annually and its electric base rates decreased by $13 million annually. An Order approving the settlement agreement was received in February 2009. The new rates were implemented effective February 6, 2009.

Regulatory Assets and Liabilities

The following regulatory assets and liabilities were included in the Balance Sheets as of December 31:

	Successor 2010	Predecessor 2009
Current regulatory assets:		
GSC and PBR (a)	$ 4	$ 3
ECR (b)	5	7
FAC (b)	3	-
Coal contracts (c)	1	-
MISO exit (d)	-	1
Other (e)	-	3
Total current regulatory assets	$ 13	$ 14
Non-current regulatory assets:		
Pension and postretirement benefits (f)	$ 213	$ 204
Other non-current regulatory assets:		
Storm restoration (d)	65	67
Mark to market impact of interest rate swaps (g)	34	-
ARO (h)	7	30
Unamortized loss on bonds (d)	22	22
Swap termination (d)	9	-
Coal contracts (c)	8	-
Unamortized debt expense	4	-
MISO exit (d)	1	4
Other (e)	4	2
Subtotal other non-current regulatory assets	154	125
Total non-current regulatory assets	$ 367	$ 329
Current regulatory liabilities:		
Coal contracts	$ 31	$ -
GSC	9	34
DSM	5	4
Emission allowances	6	-
Total current regulatory liabilities	$ 51	$ 38
Non-current regulatory liabilities:		
Accumulated cost of removal of utility plant	$ 275	$ 259
Other non-current regulatory liabilities:		
Coal contracts	87	-
OVEC power purchase contract	86	-
Deferred income taxes – net	34	41
Other (i)	1	3
Subtotal other non-current regulatory liabilities	208	44
Total non-current regulatory liabilities	$ 483	$ 303

(a) The GSC and natural gas PBR regulatory assets have separate recovery mechanisms with recovery within eighteen months.
(b) The FAC and ECR regulatory assets have separate recovery mechanisms with recovery within twelve months.
(c) Offsetting regulatory assets or liabilities for fair value purchase accounting adjustments. See Note 2, Acquisition by PPL, for information on the purchase accounting adjustments.
(d) These regulatory assets are recovered through base rates.
(e) Other regulatory assets include:
  - Mill Creek Ash Pond costs, which were recovered through base rates.
  - The CMRG and KCCS contributions, an EKPC FERC transmission settlement agreement and rate case expenses, which are recovered through base rates.
  - Offsetting regulatory asset for fair value purchase accounting adjustment for leases. See Note 2, Acquisition by PPL, for information on the purchase accounting adjustments.
(f) LG&E generally recovers this asset through pension expense included in the calculation of base rates.
(g) Beginning in the third quarter of 2010, based on an Order from the Kentucky Commission in the 2010 rate case whereby the cost of a terminated rate swap was allowed to be recovered in base rates, the mark-to-market impact of the effective and ineffective interest rate swaps is considered probable of recovery through rates and therefore included in regulatory assets. See Note 5, Derivative Financial Instruments, for further discussion.
(h) When an asset with an ARO is retired, the related ARO regulatory asset will be offset against the associated ARO regulatory liability, ARO asset and ARO liability.
(i) Other regulatory liabilities include the emission allowance purchase accounting offset and MISO exit.

GSC

LG&E's natural gas rates contain a GSC, whereby increases and decreases in the cost of natural gas supply are reflected in LG&E's rates, subject to approval by the Kentucky Commission. The GSC procedure prescribed by Order of the Kentucky Commission provides for quarterly rate adjustments to reflect the expected cost of natural gas supply in that quarter. In addition, the GSC contains a mechanism whereby any over- or under-recoveries of natural gas supply cost from prior quarters is to be refunded to or recovered from customers through the adjustment factor determined for subsequent quarters.

LG&E's GSC was modified in 1997 to incorporate a natural gas procurement incentive mechanism. Since November 1, 1997, LG&E has operated under this PBR mechanism related to its natural gas procurement activities. LG&E's rates are adjusted annually to recover (or refund) its portion of the expense (or savings) incurred during each PBR year (12 months ending October 31). Pursuant to the extension of LG&E's natural gas supply cost PBR mechanism effective November 1, 2001, the sharing mechanism under the PBR requires savings and expenses to be shared 25% with shareholders and 75% with customers up to 4.5% of the benchmarked natural gas costs. Savings and expenses in excess of 4.5% of the benchmarked natural gas costs are shared 50% with shareholders and 50% with customers. The current natural gas supply cost PBR mechanism was extended through 2010 without further modification. In December 2009, LG&E filed an application with the Kentucky Commission to extend and modify its existing natural gas cost PBR. The current PBR was set to expire at the end of October

2010. In April 2010, the Kentucky Commission issued an Order approving a five year extension and the requested minor modifications to the PBR effective November 2010.

During the PBR years ending in 2010, 2009 and 2008, LG&E achieved $8 million, $7 million and $11 million in savings, respectively. In 2010, 2009 and 2008, of the total savings amount, LG&E's portion was approximately $2 million, $2 million and $3 million, respectively, and the customers' portion was approximately $6 million in 2010, $5 million in 2009 and $8 million in 2008.

ECR

LG&E recovers the costs of complying with the Federal Clean Air Act pursuant to Kentucky Revised Statute 278-183 as amended and those federal, state or local environmental requirements which apply to coal combustion wastes and by-products from facilities utilized for production of energy from coal, 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.

The Kentucky Commission requires reviews of the past operations of the environmental surcharge for six-month and two-year billing periods to evaluate the related charges, credits and rates of return, as well as to provide for the roll-in of ECR amounts to base rates each two-year period. In December 2010, the Kentucky Commission initiated a six-month review of the Utilities' environmental surcharge for the billing period ending October 2010. An order is expected in the second quarter of 2011. Also, in December 2010, an Order was issued approving the charges and credits billed through the ECR during the six-month period ending April 2010, as well as approving billing adjustments for under-recovered costs and the rate of return on capital. In May 2010, an Order was issued approving the amounts billed through the ECR during the six-month period ending October 2009 and the rate of return on capital and allowing recovery of the under-recovery position in subsequent monthly filings. In December 2009, an Order was issued approving the charges and credits billed through the ECR during the two-year period ending April 2009, an increase in the jurisdictional revenue requirement, a base rate roll-in and a revised rate of return on capital. In July 2009, an Order was issued approving the charges and credits billed through the ECR during the six-month period ending October 2008, as well as approving billing adjustments for under-recovered costs and the rate of return on capital. In August 2008, an Order was issued approving the charges and credits billed through the ECR during the six-month periods ending April 2008 and October 2007 and the rate of return on capital. In March 2008, an Order was issued approving the charges and credits billed through the ECR during the six-month and two-year periods ending October 2006 and April 2007, respectively, 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.

In June 2009, the Company filed an application for a new ECR plan with the Kentucky Commission seeking approval to recover investments in environmental upgrades and operations and maintenance costs at the Company's generating facilities. During 2009, LG&E reached a unanimous settlement with all parties to the case and the Kentucky Commission issued an Order approving LG&E's application. Recovery on customer bills through the monthly ECR surcharge for these projects began with the February 2010 billing cycle.

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

February 2009 expense month filing, which represents a slight increase over the previously authorized 10.50%. The 10.63% return on equity for the ECR mechanism was affirmed in the 2010 rate case.

FAC

LG&E's retail electric rates contain a FAC, whereby increases and decreases in the cost of fuel for electric generation are reflected in the rates charged to retail electric customers. The FAC allows the Company to adjust billed amounts 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 December 2010, May 2010, November 2009, January 2009, May 2008 and January 2008 the Kentucky Commission issued Orders approving the charges and credits billed through the FAC for the six-month periods ending April 2010, August 2009, April 2009, April 2008, October 2007 and April 2007, respectively. In January 2009, the Kentucky Commission initiated routine examinations of the FAC for the two-year period November 1, 2006 through October 31, 2008. The Kentucky Commission issued an Order in June 2009 approving the charges and credits billed through the FAC during the review period.

Coal Contracts

In November 2010, purchase accounting adjustments were recorded for the fair value of LG&E's coal contracts. Offsetting regulatory assets or liabilities for fair value purchase accounting adjustments eliminate any ratemaking impact of the fair value adjustments.

MISO

Following receipt of applicable FERC, Kentucky Commission and other regulatory Orders, related to proceedings that had been underway since July 2003, LG&E withdrew from the MISO effective September 1, 2006. Since the exit from the MISO, LG&E has been operating under a FERC approved OATT. LG&E now contracts with the TVA to act as its transmission reliability coordinator and SPP to function as its independent transmission operator, pursuant to FERC requirements. The contractual obligations with the TVA extend through August 2011 and with SPP through August 2012.

LG&E and the MISO 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 $13 million to the MISO and made related FERC compliance filings. The Company's payment of this exit fee was with reservation of its rights to contest the amount, or components thereof, following a continuing review of its calculation and supporting documentation. LG&E 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, as well as the approved agreement providing LG&E with recovery of $2 million, of which $1 million was immediately recovered in 2008, with the remainder to be recovered over the seven years from 2008 through 2014 for credits realized from other payments the MISO will receive, plus interest.

In accordance with Kentucky Commission Orders approving the MISO exit, LG&E established a regulatory asset for the MISO exit fee, net of former MISO administrative charges collected via base rates through the base rate case test year ended April 30, 2008. The net MISO exit fee is subject to adjustment for possible future MISO credits and a regulatory liability for certain revenues associated with former MISO administrative charges, which were collected via base rates until February 6, 2009. The approved 2008 base rate case settlement provided for MISO administrative charges 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. This regulatory liability balance as of October 31, 2009 was included in the base rate case application filed on January 29, 2010. MISO exit fee credit amounts subsequent to October 31, 2009, will continue to accumulate as a regulatory liability until they 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. Based upon the 2008 FERC Orders, the Company established a reserve during the fourth quarter of 2008 of $2 million relating to potential RSG resettlement costs for the period ended December 31, 2008. However, in May 2009, after a portion of the resettlement payments had been made, the FERC issued an Order on the requests for rehearing on one November 2008 Order, which changed the effective date and reduced almost all of the previously accrued RSG resettlement costs. Therefore, these costs were reversed and a receivable was established for amounts already paid of $1 million. The MISO began refunding the amounts to the Company in June 2009, with full repayment in September 2009. In June 2009, the FERC issued an Order in the rate mismatch RSG proceeding, stating it will not require resettlements of the rate mismatch calculation from April 1, 2005 to November 4, 2007. An accrual had previously been recorded in 2008 for the rate mismatch issue for the time period April 25, 2006 to August 9, 2007, but no accrual had been recorded for the time period November 5, 2007 to November 9, 2008 based on the prior Order. Accordingly, the accrual for the former time period was reversed and an accrual for the latter time period was recorded in June 2009, with a net effect of less than $1 million of expense, substantially all of which was paid by September 2009.

In August 2009, the FERC determined that the MISO had failed to demonstrate that its proposed exemptions to real-time RSG charges were just and reasonable. In November 2009, the MISO made a compliance filing incorporating the rulings of the FERC Orders and a related task force, with a primary open issue being whether certain of the tariff changes are applied prospectively only or retroactively to approximately January 6, 2009.

In November 2009, the Utilities filed an application with the FERC to approve certain independent transmission operator arrangements to be effective upon the expiration of their current contract with SPP in September 2010. The application sought authority for LG&E and KU to function after such date as the administrators of their own OATT for most purposes. However, due to the lack of FERC approval for such an approach and the approaching expiration of the SPP contract, the Utilities determined the approach was no longer reasonably achievable without unacceptable delay and uncertainty. In July 2010, the Utilities entered into a new agreement with SPP to provide independent transmission operator services for a specified, limited time and removed its application for authority of administering its own OATT. The TVA, which currently acts as reliability coordinator, has also been retained under the existing service contract. The new agreement extends TVA services to August 2011 with no alterations or changes to the party's duties or responsibilities.

In August 2010, the FERC issued three Orders accepting most facets of several MISO RSG compliance filings. The FERC ordered the MISO to issue refunds for RSG charges that were imposed by the MISO on the assumption that there were rate mismatches for the period beginning November 5, 2007 through the present. There is no financial statement impact to the Company from this Order, as the MISO had anticipated that the FERC would require these refunds and had preemptively included them in the resettlements paid in 2009. The FERC denied the MISO's proposal to exempt certain resources from RSG charges, effective prospectively. The FERC accepted portions and rejected portions of the MISO's proposed RSG Rate Redesign Proposal, which will be effective when the software is ready for implementation subject to further compliance filings. The impact of the Redesign Proposal on the Company cannot be estimated at this time.

Pension and Postretirement Benefits

LG&E accounts for pension and postretirement benefits in accordance with the compensation – retirement benefits guidance of the FASB ASC. This guidance requires employers to recognize the over-funded or under-funded status of a defined benefit pension and postretirement plan as an asset or liability on the Balance Sheets and to recognize through other comprehensive income the changes in the funded status in the year in which the changes occur. Under the regulated operations guidance of the FASB ASC, LG&E can defer recoverable costs that would otherwise be charged to expense or equity by non-regulated entities. Current rate recovery in Kentucky is based on the compensation – retirement benefits guidance of the FASB ASC. 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 its pension and postretirement benefit 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.

Storm Restoration

In January 2009, a significant ice storm passed through LG&E's service area causing approximately 205,000 customer outages, followed closely by a severe wind storm in February 2009, causing approximately 37,000 customer outages. An application was filed with the Kentucky Commission in April 2009, requesting approval to establish a regulatory asset and defer for future recovery, approximately $45 million in incremental operation and maintenance expenses related to the storm restoration. In September 2009, the Kentucky Commission issued an Order allowing the establishment a regulatory asset of up to $45 million based on actual costs for storm damages and service restoration due to the January and February 2009 storms. In September 2009, a regulatory asset of $44 million was established for actual costs incurred and approval was received in LG&E's 2010 base rate case to recover this asset over a ten year period beginning August 1, 2010.

In September 2008, high winds from the remnants of Hurricane Ike passed through the service area causing significant outages and system damage. In October 2008, an application was filed with the Kentucky Commission requesting approval to establish a regulatory asset and defer for future recovery approximately $24 million of expenses related to the storm restoration. In December 2008, the Kentucky Commission issued an Order allowing the establishment of a regulatory asset of up to $24 million based on actual costs for storm damages and service restoration due to Hurricane Ike. In December 2008, a regulatory asset of $24 million was established for actual costs incurred and LG&E received approval in its 2010 base rate case to recover this asset over a ten year period, beginning August 1, 2010.

Interest Rate Swaps

Interest rate swaps are accounted for on a fair value basis in accordance with the derivatives and hedging guidance of the FASB ASC. Beginning in the third quarter of 2010, the unrealized gains and losses of the effective and ineffective interest rate swaps are included in a regulatory asset based on an Order from the Kentucky Commission in the 2010 rate case whereby the cost of a terminated swap was allowed to be recovered in base rates. Previously, interest rate swaps designated as effective cash flow hedges had resulting gains and losses recorded within other comprehensive income and common equity. The ineffective portion of interest rate swaps designated as cash flow hedges was previously recorded to earnings monthly, as was the entire change in the market value of the ineffective swaps. LG&E is able to recover the unrealized gains and losses on the interest rate swaps under its existing rate recovery structure as the interest expense on the swaps is realized.

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.

CMRG and KCCS Contributions

In July 2008, LG&E and KU, 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. LG&E and KU jointly agreed to provide $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. LG&E received approval from the Kentucky Commission in the Company's 2010 Kentucky base rate case to recover these regulatory assets over the requested period beginning August 1, 2010.

Rate Case Expenses

LG&E 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.

LG&E incurred $1 million in expenses related to the development and support of the 2010 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 August 2010.

DSM

DSM consists of energy efficiency programs which are intended to reduce peak demand and delay the investment in additional power plant construction, provide customers with tools and information to become better managers of their energy usage and prepare for potential future legislation governing energy efficiency. LG&E's rates contain a DSM provision which includes a rate mechanism that provides for concurrent recovery of DSM costs and provides an incentive for implementing DSM programs. The provision allows LG&E to recover revenues from lost sales associated with the DSM programs based on program plan engineering estimates and post-implementation evaluations.

In July 2007, LG&E and KU 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. In March 2008, the Kentucky Commission issued an Order approving the application, with minor modifications. LG&E and KU filed revised tariffs in April 2008, under authority of this Order, which were effective in May 2008.

Emission Allowances

In November 2010, purchase accounting adjustments were recorded for fair market value LG&E's SO_2, NOx ozone season and NOx annual emission allowances. Offsetting regulatory assets or liabilities for fair value purchase accounting adjustments eliminate any ratemaking impact of the fair value adjustments. LG&E is granted SO_2 emission allowances through 2040 and NOx ozone season and NOx annual emission allowances through 2011.

Accumulated Cost of Removal of Utility Plant

As of December 31, 2010 and 2009, LG&E segregated the cost of removal, previously embedded in accumulated depreciation, of $275 million and $259 million, respectively, in accordance with FERC Order No. 631. For reporting purposes on the Balance Sheets, LG&E presented this cost of removal as a "Regulatory liability" pursuant to the regulated operations guidance of the FASB ASC.

OVEC Power Purchase Contract

In November 2010, purchase accounting adjustments were recorded for the fair value of the power purchase agreement between LG&E and OVEC. Offsetting regulatory liabilities for fair value purchase accounting adjustments eliminate any ratemaking impact of the fair value adjustments.

Deferred Income Taxes – Net

These regulatory liabilities represent the future revenue impact from the reversal of deferred income taxes required for unamortized investment tax credits and deferred taxes provided at rates in excess of currently enacted rates.

Other Regulatory Matters

Kentucky Commission Report on Storms

In November 2009, the Kentucky Commission issued a report following review and analysis of the effects and utility response to the September 2008 wind storm and the January 2009 ice storm and possible utility industry preventative measures relating thereto. The report suggested a number of proposed or recommended preventative or responsive measures, including consideration of selective hardening of facilities, altered vegetation management programs, enhanced customer outage communications and similar measures. In March 2010, the Utilities filed a joint response reporting on their actions with respect to such recommendations. The response indicated implementation or completion of substantially all of the recommendations, including, among other matters, on-going reviews of system hardening and vegetation management procedures, certain test or pilot programs in such areas and fielding of enhanced operational and customer outage-related systems.

Wind Power Agreements

In August 2009, LG&E and KU filed a notice of intent with the Kentucky Commission indicating their intent to file an application for approval of wind power purchase contracts and cost recovery mechanisms. The contracts were executed in August 2009 and were contingent upon LG&E and KU receiving acceptable regulatory approvals. Pursuant to the proposed 20-year contracts, LG&E and KU would jointly purchase respective assigned portions of the output of two Illinois wind farms totaling an aggregate 109.5 Mw. In September 2009, the Utilities filed an application and supporting testimony with the Kentucky Commission. In October 2009, the Kentucky Commission issued an Order denying the Utilities' request to establish a surcharge for recovery of the costs of purchasing wind power. The Kentucky Commission stated that such recovery constitutes a general rate adjustment and is subject to the regulations of a base rate case. The Kentucky Commission Order provided for the request for approval of the wind power agreements to proceed independently from the request to recover the costs thereof via surcharges. In November 2009, LG&E and KU filed for rehearing of the Kentucky Commission's Order and requested that the matters of approval of the contract and recovery of the costs thereof remain the subject of the same proceeding. During December 2009, the Kentucky Commission issued data requests on this matter. In March 2010, LG&E and KU delivered notices of termination under provisions of the wind power contracts. The Utilities also filed a motion with the Kentucky Commission noting the termination of the contracts and seeking withdrawal of their application in the related regulatory proceeding. In April 2010, the Kentucky Commission issued an Order allowing the Utilities to withdraw their pending application.

Trimble County Asset Sale and Depreciation

In July 2009, the Utilities notified the Kentucky Commission of the proposed sale from the Utilities of certain ownership interests in certain existing Trimble County generating station assets which were anticipated to provide joint or common use in support of the jointly-owned TC2 generating unit under construction at the station. The undivided ownership interests sold provide KU an ownership interest in these common assets proportional to its interest in TC2 and the assets' role in supporting both TC1 and TC2. In December 2009, LG&E and KU completed the sale transaction at a price of $48 million, representing the current net book value of the assets multiplied by the proportional interest being sold.

In August 2009, the Utilities jointly filed an application with the Kentucky Commission to approve new depreciation rates for applicable jointly-owned TC2-related generating, pollution control and other plant equipment and assets. During December 2009, the Kentucky Commission extended the data discovery process through January 2010 and authorized the Utilities on an interim basis to begin using the depreciation rates for TC2 as proposed in the application. In March 2010, the Kentucky Commission issued a final Order approving the use of the proposed depreciation rates on a permanent basis.

TC2 CCN Application and Transmission Matters

An application for a CCN for construction of TC2 was approved by the Kentucky Commission in November 2005. CCNs for two transmission lines associated with TC2 were issued by the Kentucky Commission in September 2005 and May 2006. All regulatory approvals and rights of way for one transmission line have been obtained.

LG&E's and KU's CCN for a transmission line associated with the TC2 construction has been challenged by certain property owners in Hardin County, Kentucky. Certain proceedings relating to CCN challenging and federal historic preservation permit requirements have concluded with outcomes in the Utilities' favor.

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 the transmission line in some of these forums as well.

With respect to the remaining on-going dispute, LG&E's affiliate, KU obtained various successful rulings during 2008 at the Hardin County Circuit Court confirming its condemnation rights. In August 2008, several landowners appealed such rulings to the Kentucky Court of Appeals and received a temporary stay preventing KU from accessing their properties. In May 2010, the Kentucky Court of Appeals issued an Order affirming the Hardin Circuit Court's finding that KU had the right to condemn easements on the properties. In May 2010, the landowners filed a petition for reconsideration with the Court of Appeals. In July 2010, the Court of Appeals denied that petition. In August 2010, the landowners filed for discretionary review of that denial by the Kentucky Supreme Court.

Settlement discussions with the Hardin County property owners involved in the appeals of the condemnation proceedings have been unsuccessful to date. During the fourth quarter of 2008, LG&E and KU entered into settlements with certain Meade County landowners and obtained dismissals of prior litigation they brought challenging the same transmission line.

As a result of the aforementioned unresolved litigation delays encountered in obtaining access to certain properties in Hardin County, KU obtained easements to allow construction of temporary transmission facilities, bypassing those properties while the litigated issues are resolved. In September 2009, the Kentucky Commission issued an Order stating that a CCN was necessary for two segments of the proposed temporary facilities. In December 2009, the Kentucky Commission granted the CCNs for the relevant segments and the property owners have filed various motions to intervene, stay and appeal certain elements of the Kentucky Commission's recent Orders. In January 2010, in respect of two of such proceedings, the Franklin County circuit court issued Orders denying the property owners' request for a stay of construction and upholding the prior Kentucky Commission denial of their intervenor status.

Consistent with the regulatory authorizations and the favorable outcome of the legal proceedings, the Utilities completed construction activities on the permanent transmission line easements. During 2010, the Utilities placed the transmission line into operation. While the Utilities are not currently able to predict the ultimate outcome and possible financial effects of the remaining legal proceedings, the Utilities do not believe the matter involves relevant or continuing risks to operations.

Arena

In August 2006, LG&E filed an application with the Kentucky Commission requesting approval for the sale of property to the Louisville Arena Authority which was granted in a September 2006 Order. In November 2006, LG&E completed certain agreements pursuant to its August 2006 Memorandum of Understanding with the Louisville Arena Authority regarding the proposed construction of an arena in downtown Louisville. LG&E entered into a relocation agreement with the Louisville Arena Authority providing for reimbursement to LG&E of the costs to be incurred in relocating certain LG&E facilities related to the arena transaction of approximately $63 million. As of December 31, 2010, approximately $62 million of the total costs have been received. The relocation work was substantially completed during 2009, with follow up work continuing in 2010 and 2011. The parties further entered into a property sale contract providing for LG&E's sale of a downtown site to the Louisville Arena Authority which was completed for $9 million in September 2008.

Market-Based Rate Authority

In July 2006, the FERC issued an Order in LG&E's market-based rate proceeding accepting the Company's further proposal to address certain market power issues the FERC 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 balancing areas in which it may be deemed to have market power, subject to a restriction that such power will not be collusively re-sold back into such balancing areas. However, restrictions exist on sales by LG&E of power at market-based rates in the LG&E and KU and Big Rivers Electric Corporation balancing 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 the Company's power sales at balancing 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. As a condition of receiving and retaining market-based rate authority, LG&E must comply with applicable affiliate restrictions set forth in the FERC regulation. During September 2008, the Company submitted a regular triennial update filing under market-based rate regulations.

In June 2009, the FERC issued Order No. 697-C which generally clarified certain interpretations relating to power sales and purchases at balancing area interfaces or into balancing areas involving market power. In July 2009, the FERC issued an Order approving the Company's September 2008 application for market-based rate authority. During July 2009, affiliates of LG&E completed a transaction terminating certain prior generation and power marketing activities in the Big Rivers Electric Corporation balancing area, which termination should ultimately allow a filing to request a determination that the Company no longer is deemed to have market power in such balancing area.

LG&E conducts certain of its wholesale power sales activities in accordance with existing market-based rate authority principles and interpretations. Future FERC proceedings relating to Orders 697 or market-based rate authority could alter the amount of sales made at market-based versus cost-based rates. The Company's sales under market-based rate authority totaled $21 million for the year ended December 31, 2010.

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 Regional Reliability Organizations ("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. The Utilities are members of SERC, which acts as LG&E's and KU's RRO. During December 2009 and April, July and August 2010, the Utilities submitted ten self-reports relating to various standards, which self-reports remain in the early stages of RRO review and therefore, the Utilities are unable to estimate the outcome of these matters. Mandatory reliability standard settlements commonly also include non-penalty elements, including compliance steps and mitigation plans. Settlements with the SERC proceed to NERC and FERC review before becoming final. While the Utilities believe they are in compliance with the mandatory reliability standards, events of potential non-compliance may be identified from time-to-time. The Utilities cannot predict such potential violations or the outcome of self-reports described above.

Natural Gas Customer Choice Study

In April 2010, the Kentucky Commission commenced a proceeding to investigate natural gas retail competition programs; their regulatory, financial and operational aspects and potential benefits, if any, of such programs to Kentucky consumers. A number of entities, including LG&E, were parties to the proceeding. In December 2010, the Kentucky Commission issued an Order in the proceeding declining to endorse natural gas competition at the retail level, noting the existence of a number of transition or oversight costs and an uncertain level of economic benefits in such programs. With respect to existing natural gas transportation programs available to large commercial or industrial users, the Order indicates that the Kentucky Commission will review utilities' current tariff structures, user thresholds and other terms and conditions of such programs, as part of such utilities' next regular natural gas rate cases.

Integrated Resource Planning

Integrated resource planning ("IRP") regulations in Kentucky require major utilities to make triennial IRP filings with the Kentucky Commission. In April 2008, LG&E and KU 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 Kentucky Commission issued a staff report and Order closing this proceeding in December 2009. LG&E expects to file their next IRP in April 2011.

PUHCA 2005

PPL, LG&E's ultimate parent, is a holding company under PUHCA 2005. PPL, its utility subsidiaries, including LG&E 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. LG&E 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 standards within eighteen months after the enactment of EPAct 2005 and to commence consideration of Section 1254 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 and Section 1254 standards should not be adopted. However, all five Kentucky Commission jurisdictional utilities were required to file real-time pricing pilot programs for their large commercial and industrial customers. LG&E developed a real-time pricing pilot program 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 LG&E for implementation within approximately eight months. The tariff was filed in October 2008, with an effective date of December 1, 2008. LG&E files annual reports on the program within 90 days of each plan year end for the three-year pilot period.

Pursuant to an LG&E 2004 rate case settlement agreement and as referred to in the Kentucky Commission EPAct 2005 Administrative Order, LG&E made its responsive pricing and smart metering pilot program filing, which addresses real-time pricing for residential and general service customers, in March 2007. In July 2007, the Kentucky Commission approved the application as filed, for 100 residential customers and a sampling of other customers and authorized LG&E to establish the responsive pricing and smart metering pilot program, recovery of non-specific customer costs through the DSM billing mechanism and the filing of annual reports by April 1, 2009, 2010 and 2011. LG&E must also file an evaluation of the program by July 1, 2011.

Hydro Upgrade

In October 2005, LG&E received from the FERC a new license to upgrade, operate and maintain the Ohio Falls Hydroelectric Project. The license is for a period of 40 years, effective November 2005. LG&E began refurbishing the facility to add approximately 20 Mw of generating capacity in 2004 and plans to spend approximately $89 million from 2011 to 2014.

Green Energy Riders

In February 2007, LG&E and KU filed a Joint Application and Testimony for Proposed Green Energy Riders. In May 2007, a Kentucky Commission Order was issued authorizing LG&E to establish Small and Large Green Energy Riders, allowing customers to contribute funds to be used for the purchase of renewable energy credits. During November 2009, LG&E and KU filed an application to both continue and modify the existing Green Energy Programs. In February 2010, the Kentucky Commission approved the Utilities' application, as filed.

Home Energy Assistance Program

In July 2007, LG&E filed an application with the Kentucky Commission for the establishment of a Home Energy Assistance program. During September 2007, the Kentucky Commission approved the five-year program as filed, effective in October 2007. The programs were scheduled to terminate 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. As a condition in the settlement in the change of control proceeding before the Kentucky Commission in the PPL acquisition, the program was extended to September 2015.

Collection Cycle Revision

As part of its 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, in its rate case filed on July 29, 2008, 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 agreements approved in the rate cases in February 2009 changed the due date for customer bill payments to 12 days after bill issuance for both LG&E and KU.

Depreciation Study

In December 2007, LG&E filed a depreciation study with the Kentucky Commission as required by a previous Order. In August 2008, the Kentucky Commission issued an Order consolidating the depreciation study with the base rate case proceeding. The approved settlement agreement in the rate case established new depreciation rates effective February 2009.

Brownfield Development Rider Tariff

In March 2008, LG&E 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 permits 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. LG&E does not expect any financial or other impact as a result of this Order. In April 2009, LG&E filed revised net metering tariffs and application forms pursuant to the Kentucky Commission's Order. The Kentucky Commission issued an Order in April 2009, which suspended for five months all net metering tariffs filed by the jurisdictional electric utilities. This suspension was intended to allow sufficient time for review of the filed tariffs by the Kentucky Commission Staff and intervening parties.

In June 2009, the Kentucky Commission Staff held an informal conference with the parties to discuss issues related to the net metering tariffs filed by LG&E. Following this conference, the intervenors and LG&E resolved all issues and LG&E filed revised net metering tariffs with the Kentucky Commission. In August 2009, the Kentucky Commission issued an Order approving the revised tariffs.

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 non-regulated 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. The Kentucky Commission established a procedural schedule that allowed for data discovery and testimony through July 2009. In October 2009, the Kentucky Commission held an informal conference for the purpose of discussing issues related to the standard regarding the consideration of Smart Grid investments. A public hearing has not been scheduled in this matter.

Note 4 - Asset Retirement Obligations

A summary of LG&E's net ARO assets, ARO liabilities and regulatory assets established under the asset retirement and environmental obligations guidance of the FASB ASC follows:

	ARO Net Assets	ARO Liabilities	Regulatory Assets
As of December 31, 2008, Predecessor	$ 4	$ (31)	$ 29
ARO accretion and depreciation	(1)	(2)	3
ARO settlements	-	1	(2)
Removal cost incurred	-	1	-
As of December 31, 2009, Predecessor	3	(31)	30
ARO accretion and depreciation	-	(2)	2
Reclassification for retired assets	(1)	-	1
ARO revaluation - change in estimates	29	(30)	1
Removal cost incurred	-	1	-
As of October 31, 2010, Predecessor	31	(62)	34
ARO accretion and depreciation	(1)	-	1
Purchase accounting - fair value adjustment	15	13	(28)
As of December 31, 2010, Successor	$ 45	$ (49)	$ 7

In September 2010, the Company performed a revaluation of its AROs as a result of recently proposed environmental legislation and improved ability to forecast asset retirement costs due to recent construction and retirement activity.

In November 2010, the Company recorded a purchase accounting adjustment to fair value AROs due to the PPL acquisition.

Pursuant to regulatory treatment prescribed under the regulated operations guidance of the FASB ASC, an offsetting regulatory credit was recorded in "Depreciation and amortization" in the Statements of Income for the Successor of $1 million in 2010 and $2 million for the Predecessor for the ARO accretion and depreciation expense. The offsetting regulatory credit recorded was $2 million in 2009 and 2008 for the ARO accretion and depreciation expense. The ARO liabilities are offset by cash settlements that have not yet been applied. Therefore, ARO net assets, ARO liabilities and regulatory assets balances do not net to zero.

LG&E's AROs are primarily related to the final retirement of assets associated with generating units and natural gas mains and wells. LG&E transmission and distribution lines largely operate under perpetual property easement agreements which do not generally require restoration upon removal of the property.

Therefore, under the asset retirement and environmental obligations guidance of the FASB ASC, no material asset retirement obligations are recorded for transmission and distribution assets.

Note 5 - Derivative Financial Instruments

LG&E is subject to interest rate and commodity price risk related to on-going business operations. It currently manages these risks using derivative instruments, including swaps and forward contracts. The Company's policies allow for the interest rate risk to be managed through the use of fixed rate debt, floating rate debt and interest rate swaps. At December 31, 2010, LG&E's potential annual exposure to increased interest expense, based on a 10% increase in interest rates, was less than $1 million.

The Company does not net collateral against derivative instruments.

Interest Rate Swaps

LG&E uses over-the-counter interest rate swaps to limit exposure to market fluctuations in interest expense. Pursuant to Company policy, use of these derivative instruments is intended to mitigate risk, earnings and cash flow volatility and is not speculative in nature.

LG&E's interest rate swap agreements range in maturity through 2033, with aggregate notional amounts of $179 million as of December 31, 2010 and December 31, 2009. Under these swap agreements, LG&E paid fixed rates averaging 4.52% and received variable rates based on LIBOR or the Securities Industry and Financial Markets Association's municipal swap index averaging 0.23% and 0.20% at December 31, 2010 and December 31, 2009, respectively. Beginning in the third quarter of 2010, the unrealized gains and losses on the interest rate swaps are included in a regulatory asset based on an Order from the Kentucky Commission in the 2010 rate case, whereby the cost of a terminated swap was allowed to be recovered in base rates.

The fair value of the interest rate swaps is determined by a quote from the counterparty. This value is verified monthly by the Company using a model that calculates the present value of future payments under the swap utilizing current swap market rates obtained from another dealer active in the swap market and validated by market transactions. Market liquidity is considered; however, the valuation does not require an adjustment for market liquidity as the market is very active for the type of swaps used by the Company. LG&E considered the impact of its own credit risk and that of counterparties by evaluating credit ratings and financial information and adjusting market valuations to reflect such credit risk. LG&E and all counterparties had strong investment grade ratings at December 31, 2010. In addition, the Company and certain counterparties have agreed to post margin if the credit exposure exceeds certain thresholds. Cash collateral related to interest rate swaps at December 31, 2010 and December 31, 2009 was $19 million and $17 million, respectively. Cash collateral for interest rate swaps is classified as a long-term "Other asset" on the accompanying Balance Sheets.

The table below shows the fair value and Balance Sheets location of interest rate swap derivatives:

	Fair Value	
	Successor	Predecessor
Balance Sheet Location	December 31, 2010	December 31, 2009
Current derivative liability	$ 2	$ -
Long-term derivative liability	32	28
	$ 34	$ 28

The interest rate swaps are accounted for on a fair value basis in accordance with the derivatives and hedging guidance of the FASB ASC. The tables below show the pre-tax amount and income statement location of derivative gains and losses for the change in the mark-to-market value of the interest rate swaps, realized losses and the change in the ineffective portion of the interest rate swaps deemed highly effective, during the periods ended December 31, 2010, October 31, 2010, December 31, 2009 and December 31, 2008, including the impact of reclassifying these amounts to regulatory assets during the period ended October 31, 2010. For the period ended October 31, 2010, LG&E recorded a pre-tax gain of less than $1 million in interest expense to reflect the change in the ineffective portion of the interest rate swaps deemed highly effective and recorded pre-tax gains of $21 million and $9 million, respectively, to reflect the reclassification of the ineffective swaps and the terminated swap to a regulatory asset:

		Successor	Predecessor		
		November 1, 2010 through	January 1, 2010 through	Year Ended December 31,	
Gain (Loss) Recognized in Income	Location	December 31, 2010	October 31, 2010	2009	2008
Change in the ineffective portion deemed highly effective	Interest expense	$ -	$ -	$ 1	$ (8)
Reclassification to regulatory assets of unrealized gain on interest rate swaps	Derivative gain (loss)	-	21	-	-
Unrealized gain (loss) on ineffective swaps	Derivative gain (loss)	-	(10)	21	(35)
Reclassification to regulatory assets of unrealized gain on terminated swap	Derivative gain (loss)	-	9	-	
Realized loss on swaps	Derivative gain(loss)	-	(1)	(3)	(2)
		$ -	$ 19	$ 19	$ (45)

No gain or loss on hedging interest rate swaps was recognized in other comprehensive income for the periods ended December 31, 2010 and October 31, 2010. The gain on interest rate swaps recognized in other comprehensive income for the year ended December 31, 2009 was $5 million, and the loss on interest rate swaps recognized in other comprehensive income for the year ended December 31, 2008, was $8 million. For the period ended October 31, 2010, the gain on derivatives reclassified from "Accumulated other comprehensive income" to "Regulatory assets" was $23 million.

Prior to including the unrealized gains and losses on the interest rate swaps in regulatory assets, amounts previously recorded in accumulated other comprehensive income were reclassified into earnings in the same period during which the derivative forecasted transaction affected earnings. No amount was amortized from accumulated other comprehensive income to income in the period ended December 31, 2010, and in the periods ended October 31, 2010, December 31, 2009 and December 31, 2008, amortization was less than $1 million each year.

A decline of 100 basis points in the current market interest rates would reduce the fair value of LG&E's interest rate swaps by $28 million.

Energy Trading and Risk Management Activities

LG&E 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 the derivatives and hedging guidance of the FASB ASC.

Energy trading and risk management contracts are valued using prices based on active trades from Intercontinental Exchange Inc. In the absence of a traded price, midpoints of the best bids and offers are the primary determinants of valuation. When sufficient trading activity is unavailable, other inputs 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. 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 2010 or 2009. Changes in market pricing, interest rate and volatility assumptions were made during both years.

The table below shows the fair value and balance sheet location of energy trading and risk management derivative contracts:

Non Hedging Derivatives:	Fair Value	
	Successor	Predecessor
Balance Sheet Location	December 31, 2010	December 31, 2009
Asset derivative		
Prepayments and other current assets (a)	$ -	$ 2
Liability derivative		
Other current liabilities	$ 2	$ 2

(a) The amount recorded in prepayments and other current assets totals less than $1 million.

Assets and liabilities from long-term energy trading and risk management derivative contracts total less than $1 million at December 31, 2010 and were zero at December 31, 2009.

The Company maintains credit policies intended to minimize credit risk in wholesale marketing and trading activities by assessing the creditworthiness of potential counterparties prior to entering into transactions with them and continuing to evaluate their creditworthiness once transactions have been initiated. To further mitigate credit risk, LG&E seeks to enter into netting agreements or require cash deposits, letters of credit and parental company guarantees as security from counterparties. The Company uses ratings of S&P, Moody's and definitive qualitative and quantitative data to assess the financial strength of counterparties on an on-going basis. If no external rating exists, LG&E assigns an internally generated rating for which it sets appropriate risk parameters. As risk management contracts are valued based on changes in market prices of the related commodities, credit exposures are revalued and monitored on a daily basis. At December 31, 2010, 100% of the trading and risk management commitments were with counterparties rated BBB-/Baa3 equivalent or better. The Company has reserved against counterparty credit risk based on LG&E's own creditworthiness (for net liabilities) and its counterparty's creditworthiness (for net assets). The Company applies historical default rates within varying credit ratings over time provided by S&P or Moody's. At December 31, 2010 and December 31, 2009, counterparty credit reserves related to energy trading and risk management contracts were zero and less than $1 million respectively.

The net volume of electricity based financial derivatives outstanding at December 31, 2010 and December 31, 2009, was 869,101 Mwh and 315,600 Mwh, respectively. Cash collateral related to the energy trading and risk management contracts was $3 million and $2 million at December 31, 2010 and December 31, 2009, respectively. Cash collateral related to the energy trading and risk management contracts is recorded in "Prepayments and other current assets" on the Balance Sheets.

LG&E manages the price risk of its estimated future excess economic generation capacity using market-traded forward contracts. Hedge accounting treatment has not been elected for these transactions; therefore, realized and unrealized gains and losses are included in the Statements of Income.

The following table presents the effect of market-traded forward contract derivatives not designated as hedging instruments on income:

		Successor	Predecessor		
Gain (Loss) Recognized in Income	Location	November 1, 2010 through December 31, 2010	January 1, 2010 through October 31, 2010	Year Ended December 31, 2009	Year Ended December 31, 2008
Realized gain	Electric revenues	$ -	$ 3	$ 10	$ 3
Unrealized gain (loss)	Electric revenues	(1)	-	(1)	1
		$ (1)	$ 3	$ 9	$ 4

Credit Risk Related Contingent Features

Certain of LG&E's derivative contracts contain credit contingent provisions which would permit the counterparties with which LG&E is in a net liability position to require the transfer of additional collateral upon a decrease in LG&E's credit rating. Some of these provisions would require LG&E to transfer additional collateral or permit the counterparty to terminate the contract if LG&E's credit rating were to fall below investment grade. Some of these provisions also allow the counterparty to require additional collateral upon each decrease in the credit rating at levels that remain above investment grade. In either case, if LG&E's credit rating were to fall below investment grade (i.e., below BBB- for S&P or Baa3 for Moody's) and assuming no assignment to an investment grade affiliate were allowed, most of these credit contingent provisions require either immediate payment of the net liability as a termination payment or immediate and ongoing full collateralization by LG&E on derivative instruments in net liability positions.

Additionally, certain of LG&E's derivative contracts contain credit contingent provisions that require LG&E to provide "adequate assurance" of performance if the other party has reasonable grounds for insecurity regarding LG&E's performance of its obligation under the contract. A counterparty demanding adequate assurance could require a transfer of additional collateral or other security, including letters of credit, cash and guarantees from a creditworthy entity. A demand for additional assurance would typically involve negotiations among the parties. However, amounts disclosed below represent assumed immediate payment or immediate and ongoing full collateralization for derivative instruments in net liability positions with "adequate assurance" provisions.

To determine net liability positions, LG&E uses the fair value of each agreement. The aggregate fair value of all derivative instruments with the credit contingent provisions described above that were in a net liability position at December 31, 2010 was $25 million of which LG&E had posted collateral of $19 million in the normal course of business. At December 31, 2010, if the credit contingent provisions underlying these derivative instruments were triggered due to a credit downgrade below investment grade, LG&E would have been required to post an additional $6 million of collateral to its counterparties.

Note 6 - Fair Value Measurements

LG&E adopted the fair value guidance in the FASB ASC in two phases. Effective January 1, 2008, the Company adopted it for all financial instruments and non-financial instruments accounted for at fair value on a recurring basis, and effective January 1, 2009, the Company adopted it for all non-financial instruments accounted for at fair value on a non-recurring basis. The FASB ASC guidance clarifies that fair value is an exit price, representing the amount that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants. As such, fair value is a market-based measurement that should be determined based on assumptions that market participants would use in pricing an asset or a liability. As a basis for considering such assumptions, the FASB ASC guidance establishes a three-tier value hierarchy, which prioritizes the inputs used in the valuation methodologies in measuring fair value.

The carrying values and estimated fair values of LG&E's non-trading financial instruments follow:

	Successor		Predecessor	
	December 31, 2010		December 31, 2009	
	Carrying Value	Fair Value	Carrying Value	Fair Value
Long-term bonds	$ 1,112	$ 1,069	$ 411	$ 411
Long-term debt to affiliated company	-	-	485	512
Derivative liabilities – interest rate swaps	32	32	28	28

The long-term fixed rate pollution control bond valuations reflect prices quoted by investment banks, which are active in the market for these instruments. First mortgage bond valuations reflect prices quoted from a third party service. The fair value of the long-term debt due to affiliated company is determined using an internal valuation model that discounts the future cash flows of each loan at current market rates as determined based on quotes from investment banks that are actively involved in capital markets for utilities and factor in LG&E's credit ratings and default risk. The fair values of the interest rate swaps reflect price quotes from investment banks, consistent with the fair value measurements and disclosures guidance of the FASB ASC. This value is verified monthly by the Company using a model that calculates the present value of future payments under the swap utilizing current swap market rates obtained from another dealer active in the swap market and validated by market transactions. The fair values of cash and cash equivalents, accounts receivable, accounts payable and notes payable are substantially the same as their carrying values.

LG&E has classified the applicable financial assets and liabilities that are accounted for at fair value into the three levels of the fair value hierarchy, as discussed in Note 1, Summary of Significant Accounting Policies.

The Company classifies its derivative cash collateral balances within level 1 based on the funds being held in a demand deposit account. The Company classifies its derivative energy trading and risk management contracts and interest rate swaps within level 2 because it values them using prices actively quoted for proposed or executed transactions, quoted by brokers or observable inputs other than quoted prices.

The following tables set forth, by level within the fair value hierarchy, LG&E's financial assets and liabilities that were accounted for at fair value on a recurring basis.

December 31, 2010	Level 1	Level 2	Level 3	Total
Financial assets:				
Cash and cash equivalents	$ 2	$ -	$ -	$ 2
Short-term investments - municipal debt securities	163	-	-	163
Energy trading and risk management contracts	3	-	-	3
Restricted cash	19	-	-	19
Total financial assets	$ 187	$ -	$ -	$ 187
Financial liabilities:				
Energy trading and risk management contracts	$ -	$ 2	$ -	$ 2
Interest rate swaps	-	34	-	34
Total financial liabilities	$ -	$ 36	$ -	$ 36

December 31, 2009	Level 1	Level 2	Level 3	Total
Financial assets:				
Energy trading and risk management contract cash collateral	$ 2	$ -	$ -	$ 2
Energy trading and risk management contracts	-	2	-	2
Interest rate swap cash collateral	17	-	-	17
Total financial assets	$ 19	$ 2	$ -	$ 21
Financial liabilities:				
Energy trading and risk management contracts	$ -	$ 2	$ -	$ 2
Interest rate swaps	-	28	-	28
Total financial liabilities	$ -	$ 30	$ -	$ 30

There were no level 3 measurements for the periods ending December 31, 2010 and December 31, 2009.

Note 7 - Goodwill and Intangible Assets

In connection with PPL's acquisition of LKE and its subsidiaries, goodwill was recorded on November 1, 2010. In addition, as of November 1, 2010, certain intangible assets were adjusted to their fair value and new intangible assets were recorded. See Note 2, Acquisition by PPL, for further information.

Goodwill

The Company performs its required annual goodwill impairment test in the fourth quarter. Impairment tests are performed between the annual tests when the Company determines that a triggering event has occurred that would, more likely than not, reduce the fair value of a reporting unit below its carrying value. The goodwill impairment test is comprised of a two-step process. In step 1, the Company identifies a potential impairment by comparing the estimated fair value of the regulated utilities (the goodwill reporting unit) to their carrying value, including goodwill, on the measurement date. If the estimated fair value exceeds its carrying amount, goodwill is not considered impaired. If the fair value is less than the carrying value, then step 2 is performed to measure the amount of impairment loss, if any. The step 2 calculation compares the implied fair value of the goodwill to the carrying value of the goodwill. The implied fair value of goodwill is equal to the excess of the company's estimated fair value over the fair values of its identified assets and liabilities. If the carrying value of goodwill exceeds the implied fair value of goodwill, an impairment loss is recognized in an amount equal to that excess (but not in excess of the carrying value).

In connection with PPL's acquisition of LKE on November 1, 2010, LG&E recorded goodwill on November 1, 2010. The allocation of the goodwill to LG&E was based on the net asset value of the Company. The goodwill represents value paid for the rate regulated business located in a defined service area with a constructive regulatory environment, which provides for future investment, earnings and cash flow growth, as well as the talented and experienced workforce. LG&E's franchise values are being attributed to the going concern value of the business, and thus were recorded as goodwill rather than a separately identifiable intangible asset. None of the goodwill recognized is deductible for income tax purposes or included in customer rates. See Note 2, Acquisition by PPL, for further information.

For the 2010 annual impairment test, the primary valuation technique used was an income methodology based on management's estimates of forecasted cash flows for LG&E, with those cash flows discounted to present value using rates commensurate with the risks of those cash flows. Management also took into consideration the acquisition price paid by PPL. The discounted cash flows for LG&E were based on discrete financial forecasts developed by management for planning purposes and consistent with those given to PPL. Cash flows beyond the discrete forecasts were estimated using a terminal-value calculation, which incorporated historical and forecasted financial trends for LG&E. No impairment resulted from the fourth quarter test, as the determined fair value of LG&E was greater than its carrying value.

Other Intangible Assets

The gross carrying amount and the accumulated amortization of other intangible assets were as follows:

	Successor	
	December 31, 2010	
	Gross Carrying Amount	Accumulated Amortization
Subject to amortization:		
Coal contracts (a)	$ 124	$ 6
Land rights (b)	6	-
Emission allowances (c)	8	1
OVEC power purchase agreement (d)	87	1
Total other intangible assets	$ 225	$ 8

(a) The gross carrying amount represents the fair value of coal contracts recognized as a result of the 2010 acquisition by PPL. The weighted average amortization period of these contracts is three years. See Note 2, Acquisition by PPL, for further information.
(b) The gross carrying amount represents the fair value of land rights recognized as a result of adopting PPL's accounting policies in the Successor period. The weighted average amortization period of these rights is 10 years. See Note 1, Summary of Significant Accounting Policies, for further information.
(c) The gross carrying amount represents the fair value of emission allowances recognized as a result of the 2010 acquisition by PPL, as well as the reclassification of amounts from inventory to intangible assets as a result of adopting PPL's accounting policies in the Successor period. The weighted average amortization period of these emission allowances is three years. See Note 2, Acquisition by PPL, for further information.
(d) The gross carrying amount represents the fair value of the OVEC power purchase contract recognized as a result of the 2010 acquisition by PPL. The weighted average amortization period of the power purchase agreement is 8 years. See Note 2, Acquisition by PPL, for further information.

Current intangible assets and long-term intangible assets are included in "Other intangible assets" in their respective areas on the Balance Sheets in 2010. Intangible assets of LG&E resulting from purchasing accounting adjustments are not recoverable in rates.

Amortization expense, excluding consumption of emission allowances, was $7 million for the Successor in 2010. The estimated aggregate amortization expense for each of the next five years is as follows:

	Estimated Expense in Period Ended				
	2011	2012	2013	2014	2015
Aggregate amortization expense	$ 45	$ 23	$ 25	$ 23	$ 24

Note 8 - 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.

LG&E's customer receivables arise from deliveries of electricity and natural gas. Electric revenues represented 77%, 72% and 69% of LG&E's revenues for 2010, 2009 and 2008, respectively. Natural gas revenues represented 23%, 28% and 31% of LG&E's revenues for 2010, 2009 and 2008, respectively. During 2010, the Company's 10 largest electric and natural gas customers accounted for less than 11% and less than 14% of total volumes, respectively. Volumes associated with the ten largest natural gas customers were predominantly for transportation service.

Effective November 2008, LG&E and its employees represented by the IBEW Local 2100 entered into a three-year collective bargaining agreement. This agreement provides for negotiated increases or changes to wages, benefits or other provisions. The employees represented by this bargaining agreement comprise approximately 68% of the Company's workforce at December 31, 2010.

Note 9 - Pension and Other Postretirement Benefit Plans

LG&E employees benefit from both funded and unfunded retirement benefit plans. Its defined benefit pension plans cover employees hired by December 31, 2005.Employees hired after this date participate in the Retirement Income Account ("RIA"), a defined contribution plan. The postretirement plan includes health care benefits that are contributory with participants' contributions adjusted annually. The Company 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 defined benefit plans' obligations, the fair value of assets and the funded status of the plan for November 1, 2010 through December 31, 2010, for the Successor, and for January 1, 2010 through October 31, 2010, and January 1, 2009 through December 31, 2009, for the Predecessor:

	Pension Benefits			Other Postretirement Benefits		
	Successor	Predecessor		Successor	Predecessor	
	2010	2010	2009	2010	2010	2009
Change in benefit obligation:						
Benefit obligation at beginning of period	$ 485	$ 441	$ 429	$ 92	$ 90	$ 88
Service cost	1	3	4	-	1	1
Interest cost	4	21	26	1	4	5
Benefits paid, net of retiree contributions	(4)	(22)	(27)	(1)	(5)	(6)
Actuarial (gain) loss and other	(3)	42	9	(1)	2	2
Benefit obligation at end of period	$ 483	$ 485	$ 441	$ 91	$ 92	$ 90

	Pension Benefits			Other Postretirement Benefits		
	Successor	Predecessor		Successor	Predecessor	
	2010	2010	2009	2010	2010	2009
Change in plan assets:						
Fair value of plan assets at beginning of period	$ 352	$ 325	$ 286	$ 6	$ 5	$ 3
Actual return on plan assets	9	30	59	-	-	-
Employer contributions	-	20	8	1	6	8
Benefits paid, net of retiree contributions	(4)	(22)	(27)	(1)	(5)	(6)
Administrative expenses and other	-	(1)	(1)	-	-	-
Fair value of plan assets at end of period	$ 357	$ 352	$ 325	$ 6	$ 6	$ 5
Funded status at end of period	$ (126)	$ (133)	$ (116)	$ (85)	$ (86)	$ (85)

Amounts Recognized in the Balance Sheets

The following tables provide the amounts recognized in the Balance Sheets and information for plans with benefit obligations in excess of plan assets for November 1, 2010 through December 31, 2010, for the Successor, and for January 1, 2010 through October 31, 2010, and January 1, 2009 through December 31, 2009, for the Predecessor:

	Pension Benefits			Other Postretirement Benefits		
	Successor	Predecessor		Successor	Predecessor	
	2010	2010	2009	2010	2010	2009
Regulatory assets	$ 197	$ 209	$ 188	$ 16	$ 17	$ 16
Accrued benefit liability (current)	-	-	-	(1)	-	(3)
Accrued benefit liability (non-current)	(126)	(133)	(116)	(84)	(86)	(82)

Amounts recognized in regulatory assets and liabilities for November 1, 2010 through December 31, 2010, for the Successor, and for January 1, 2010 through October 31, 2010, and January 1, 2009 through December 31, 2009, for the Predecessor consist of:

	Pension Benefits			Other Postretirement Benefits		
	Successor	Predecessor		Successor	Predecessor	
	2010	2010	2009	2010	2010	2009
Transition obligation	$ -	$ -	$ -	$ 1	$ 2	$ 2
Prior service cost	27	28	32	5	5	6
Accumulated loss	170	181	156	10	10	8
Total regulatory assets	$ 197	$ 209	$ 188	$ 16	$ 17	$ 16

Additional information for plans with accumulated benefit obligations in excess of plan assets for November 1, 2010 through December 31, 2010, for the Successor, and for January 1, 2010 through October 31, 2010, and January 1, 2009 through December 31, 2009, for the Predecessor consists of:

	Pension Benefits			Other Postretirement Benefits		
	Successor	Predecessor		Successor	Predecessor	
	2010	2010	2009	2010	2010	2009
Benefit obligation	$ 483	$ 485	$ 441	$ 91	$ 92	$ 90
Accumulated benefit obligation	450	449	408	-	-	-
Fair value of plan assets	357	352	325	6	6	5

The amounts recognized in regulatory assets for November 1, 2010 through December 31, 2010, for the Successor, and for January 1, 2010 through October 31, 2010, and January 1, 2009 through December 31, 2009, for the Predecessor:

	Pension Benefits			Other Postretirement Benefits		
	Successor	Predecessor		Successor	Predecessor	
	2010	2010	2009	2010	2010	2009
Net (gain) loss arising during the period	$ (8)	$ 33	$ (27)	$ (1)	$ 2	$ 1
Amortization of prior service cost	(1)	(4)	(6)	-	(1)	(2)
Amortization of transitional obligation	-	-	-	-	-	(1)
Amortization of (loss) gain	(3)	(8)	(12)	-	-	1
Total amounts recognized in regulatory assets and liabilities	$ (12)	$ 21	$ (45)	$ (1)	$ 1	$ (1)

For discussion of the pension and postretirement regulatory assets, see Note 3, 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 LG&E employees and Servco employees, who provide services to LG&E. The Servco costs are allocated to LG&E based on employees' labor charges and are approximately 44%, 43% and 42% of Servco's costs for 2010, 2009 and 2008, respectively.

	Pension Benefits					
	Successor			Predecessor		
	November 1, 2010 through December 31, 2010			January 1, 2010 through October 31, 2010		
	LG&E	Servco Allocation to LG&E	Total LG&E	LG&E	Servco Allocation to LG&E	Total LG&E
Service cost	$ 1	$ 1	$ 2	$ 3	$ 4	$ 7
Interest cost	4	1	5	22	5	27
Expected return on plan assets	(4)	(1)	(5)	(21)	(4)	(25)
Amortization of prior service cost	1	-	1	4	1	5
Amortization of actuarial gain	2	1	3	8	1	9
Net periodic benefit cost	$ 4	$ 2	$ 6	$ 16	$ 7	$ 23

	Pension Benefits					
	Predecessor - Year Ended December 31, 2009			Predecessor - Year Ended December 31, 2008		
	LG&E	Servco Allocation to LG&E	Total LG&E	LG&E	Servco Allocation to LG&E	Total LG&E
Service cost	$ 4	$ 4	$ 8	$ 4	$ 4	$ 8
Interest cost	26	6	32	26	5	31
Expected return on plan assets	(23)	(4)	(27)	(32)	(5)	(37)
Amortization of prior service cost	6	1	7	6	1	7
Amortization of actuarial gain	12	2	14	1	-	1
Net periodic benefit cost	$ 25	$ 9	$ 34	$ 5	$ 5	$ 10

	Other Postretirement Benefits					
	Successor			Predecessor		
	November 1, 2010 through December 31, 2010			January 1, 2010 through October 31, 2010		
	LG&E	Servco Allocation to LG&E	Total LG&E	LG&E	Servco Allocation to LG&E	Total LG&E
Service cost	$ -	$ -	$ -	$ 1	$ 1	$ 2
Interest cost	1	-	1	4	-	4
Amortization of prior service cost	-	-	-	1	-	1
Net periodic benefit cost	$ 1	$ -	$ 1	$ 6	$ 1	$ 7

	Other Postretirement Benefits					
	Predecessor - Year Ended December 31, 2009			Predecessor - Year Ended December 31, 2008		
	LG&E	Servco Allocation to LG&E	Total LG&E	LG&E	Servco Allocation to LG&E	Total LG&E
Service cost	$ 1	$ 1	$ 2	$ 1	$ 1	$ 2
Interest cost	5	-	5	5	-	5
Amortization of transitional obligation	2	-	2	2	-	2
Net periodic benefit cost	$ 8	$ 1	$ 9	$ 8	$ 1	$ 9

The estimated amounts that will be amortized from regulatory assets into net periodic benefit cost in 2011 are shown in the following table:

	Pension Benefits	Other Postretirement Benefits
Regulatory assets and liabilities:		
Net actuarial loss	$ 14	$ -
Prior service cost	4	1
Transition obligation	-	1
Total regulatory assets and liabilities amortized during 2011	$ 18	$ 2

The weighted average assumptions used in the measurement of LG&E's pension and postretirement benefit obligations for November 1, 2010 through December 31, 2010, for the Successor, and for January 1, 2010 through October 31, 2010, and January 1, 2009 through December 31, 2009, for the Predecessor are shown in the following table:

	Successor	Predecessor	
	2010	2010	2009
Discount rate – union plan	5.39%	5.32%	6.08%
Discount rate – non-union plan	5.52%	5.46%	6.13%
Discount rate - postretirement	5.12%	4.96%	5.82%
Rate of compensation increase	5.25%	5.25%	5.25%

For the first ten months of 2010, the discount rates used to determine the pension and postretirement benefit obligations and the period expense were determined using the Mercer Pension Discount Yield Curve. This model takes the plans' cash flows and matches them to a yield curve that provides the equivalent yields on zero-coupon corporate bonds for each maturity. The discount rate is the single rate that produces the same present value of cash flows. The selection of the various discount rates represents the equivalent single rate under a broad-market AA yield curve constructed by Mercer.

For the last two months of 2010, the Towers Watson Yield Curve was used to determine the discount rate. This model starts with an analysis of the expected benefit payment stream for its plans. This information is first matched against a spot-rate yield curve. A portfolio of Aa-graded non-callable (or callable with make-whole provisions) bonds, with a total amount outstanding in excess of $667 billion, serves as the base from which those with the lowest and highest yields are eliminated to develop the ultimate yield curve. The results of this analysis are considered together with other economic data and movements in various bond indices to determine the discount rate assumption.

The weighted average assumptions used in the measurement of LG&E's pension and postretirement net periodic benefit costs for November 1, 2010 through December 31, 2010, for the Successor, and for January 1, 2010 through October 31, 2010, and January 1, 2009 through December 31, 2009, for the Predecessor are shown in the following table:

	Successor	Predecessor		
	2010	2010	2009	2008
Discount rate – union plan	5.28%	6.08%	6.33%	6.56%
Discount rate – non-union plan	5.45%	6.13%	6.25%	6.66%
Discount rate – postretirement benefits	4.94%	5.82%	6.36%	6.56%
Expected long-term return on plan assets	7.25%	7.75%	8.25%	8.25%
Rate of compensation increase	5.25%	5.25%	5.25%	5.25%

To develop the expected long-term rate of return on assets assumption, LG&E 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 current asset allocation to develop the expected long-term rate of return on assets assumption for the portfolio. The Company has determined that the 2011 expected long-term rate of return on assets assumption should be 7.25%.

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

- A 1% change in the assumed discount rate would have a $58 million positive or negative impact to the 2010 accumulated benefit obligation and a $66 million positive or negative impact to the 2010 projected benefit obligation.
- A 25 basis point change in the expected rate of return on assets would have resulted in less than a $1 million positive or negative impact to 2010 pension expense.
- A 25 basis point increase in the rate of compensation increase would have a $2 million negative impact to the 2010 projected benefit obligation.

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 the first ten months of 2010. The rate was assumed to decrease gradually to 4.5% by 2029 and remain at that level thereafter. For the last two months of 2010, an 8% annual increase in the per capita cost of covered health care benefits was assumed, and the rate was assumed to decrease gradually to 5.5% by 2019. For 2011, a 9% annual increase in the per capita cost of covered health care benefits is assumed, and the rate is assumed to decrease gradually to 5.5% by 2019. This change in the length of the health care trend was made to conform to PPL's accounting policies.

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 to the 2010 total of service and interest costs components and an increase or decrease of less than $2 million in year end 2010 postretirement benefit obligations.

Expected Future Benefit Payments

The following list provides the amount of expected future benefit payments, which reflect expected future service cost:

	Pension Benefits	Other Postretirement Benefits
2011	$ 26	$ 7
2012	26	7
2013	25	7
2014	25	7
2015	26	7
2016-2020	144	35

Plan Assets

The following table shows the pension plans' weighted average asset allocation by asset category at December 31:

	Target Range	Successor 2010	Predecessor 2009
Equity securities	45% - 75%	58%	59%
Debt securities	30% - 50%	41%	40%
Other	0% - 10%	1%	1%
Totals		100%	100%

The investment policy of the pension plans was developed in conjunction with financial and actuarial consultants, investment advisors and legal counsel. The goal of the investment policy is to preserve the capital of the pension plans' assets and maximize investment earnings in excess of inflation with acceptable levels of volatility. The return objective is to exceed the benchmark return for the policy index comprised of the following: Russell 3000 Index, MSCI-EAFE Index, Barclays Capital Aggregate and Barclays Capital 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 over rolling three and five year periods. 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 are either 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.

LG&E has classified plan assets that are accounted for at fair value into the three levels of the fair value hierarchy, as defined by the fair value measurements and disclosures guidance of the FASB ASC. See Note 6, Fair Value Measurements, for further information.

A financial instrument's level within the fair value hierarchy is based on the lowest level of any input that is significant to the fair value measurement. Valuation techniques used need to maximize the use of observable inputs and minimize the use of unobservable inputs.

A description of the valuation methodologies used to measure plan assets at fair value is provided below:

Money market fund: These investments are public investment vehicles valued using $1 for the net asset value. The money market funds are classified within level 2 of the valuation hierarchy.

Common/collective trusts: Valued based on the beginning of year value of the plan's interests in the trust plus actual contributions and allocated investment income (loss) less actual distributions and allocated administrative expenses. Quoted market prices are used to value investments in the trust. The fair value of certain other investments for which quoted market prices are not available are valued based on yields currently available on comparable securities of issuers with similar credit ratings. The common/collective trusts are classified within level 2 of the valuation hierarchy.

The preceding methods described may produce a fair value that may not be indicative of net realizable value or reflective of future fair values. Furthermore, although the Company believes its valuation methods are appropriate and consistent with other market participants, the use of different methodologies or assumptions to determine the fair value of certain financial instruments could result in a different fair value measurement at the reporting date. There were no changes in the plans' valuation methodologies during 2010.

The following table sets forth, by level within the fair value hierarchy, the plans' assets at fair value at December 31:

	Successor	Predecessor
	2010	2009
	Level 2	Level 2
Money market fund	$ 2	$ 2
Common/collective trusts	361	328
Total investments at fair value	$ 363	$ 330

There are no assets categorized as level 1 or level 3 as of December 31, 2010 and December 31, 2009.

Contributions

LG&E made a discretionary contribution to the pension plan of $20 million in 2010 and $8 million in 2009. Servco made discretionary contributions to its pension plan of $9 million and $8 million in 2010 and 2009, 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. The Company made contributions totaling $64 million in January 2011. See Note 19, Subsequent Events, for further information.

The Company made contributions to its other postretirement benefit plan of $7 million in 2010 and 2009. In 2011, the Company 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's plans met the minimum funding requirements as defined by the Pension Protection Act of 2006 for years ended December 31, 2010 and 2009.

Thrift Savings Plans

LG&E 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. LG&E makes contributions to the plan by matching a portion of the employees' contributions. The costs of this matching were $3 million in 2010, 2009 and 2008.

LG&E also makes contributions to RIAs within the thrift savings plans for certain employees not covered by the noncontributory defined benefit pension plans. These employees consist of those hired after December 31, 2005. The Company makes these contributions based on years of service and the employees' wage and salary levels, and makes them in addition to the matching contributions discussed above. The amounts contributed by the Company under this arrangement were less than $1 million in 2010, 2009 and 2008.

Health Care Reform

In March 2010, Health Care Reform (the Patient Protection and Affordable Care Act of 2010) was signed into law. Many provisions of Health Care Reform do not take effect for an extended period of time and many aspects of the law which are currently unclear or undefined will likely be clarified in future regulations.

Specific provisions within Health Care Reform that may impact LG&E include:

- Beginning in 2011, requirements extend dependent coverage up to age 26, remove the $2 million lifetime maximum and eliminate cost sharing for certain preventative care procedures.
- Beginning in 2018, a potential excise tax is expected on high-cost plans providing health coverage that exceeds certain thresholds.

The Company has evaluated these provisions of Health Care Reform on its benefit programs in consultation with its actuarial consultants and has determined that the excise tax will not have an impact on its postretirement medical plans. The requirement to extend dependent coverage up to age 26 is not expected to have a significant impact on active or retiree medical costs. The Company will continue to monitor the potential impact of any changes to the existing provisions and implementation guidance related to Health Care Reform on its benefit programs.

Note 10 - Income Taxes

LG&E's federal income tax return is included in a United States consolidated income tax return filed by LKE's direct parent. Prior to October 31, 2010 the return was included in the consolidated return of E.ON US Investments Corp. Due to the acquisition by PPL, the return will be included in the consolidated PPL return beginning November 1, 2010, for each tax period. Each subsidiary of the consolidated tax group, including LG&E, 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. The Company also files income tax returns in various state jurisdictions. While 2007 and later years are open under the federal statute of limitations, Revenue Agent Reports for 2007-2008 have been received from the IRS, effectively closing these years to additional audit adjustments. Tax years beginning with 2007 were examined under an IRS program, 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. Adjustments for 2007, agreed to and recorded in January 2009, were comprised of $5 million of depreciable temporary differences. For 2008, the IRS allowed additional deductions in connection with the Company's application for a change in repair deductions and disallowed certain bonus depreciation claimed on the original return. The net temporary tax impact for the Company was a $13 million reduction in tax and was recorded in 2010. The 2009 federal return was filed in the third quarter of 2010 and the IRS issued a Partial Acceptance Letter in connection with CAP. The IRS is continuing to review bonus depreciation, storms and other repairs, contributions in aid of construction and purchased natural gas adjustments. No net adverse impact is expected from these remaining areas. The short tax year beginning January 1, 2010 through October 31, 2010, is also being examined under CAP. No material items have been raised by the IRS at this time. The two month period beginning November 1, 2010 and ending December 31, 2010 is not currently under examination.

Additions and reductions of uncertain tax positions during 2010, 2009 and 2008 were less than $1 million. Possible amounts of uncertain tax positions for LG&E 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. If recognized, the less than $1 million of unrecognized tax benefits would reduce the effective income tax rate.

The amount LG&E recognized as interest expense and interest accrued related to unrecognized tax benefits was less than $1 million for the twelve month periods ended and as of December 31, 2010, 2009 and 2008. The interest expense and interest accrued is based on IRS and Kentucky Department of Revenue large corporate interest rates for underpayment of taxes. At the date of adoption, the Company accrued less than $1 million in interest expense on uncertain tax positions. LG&E records the interest as "Interest expense" and penalties, if any, as "Operating expenses" on the Statements of Income and "Other current liabilities" on the Balance Sheets, on a pre-tax basis. No penalties were accrued by the Company through December 31, 2010.

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

	Successor	Predecessor		
	November 1, 2010 through December 31, 2010	January 1, 2010 through October 31, 2010	Year Ended December 31, 2009	Year Ended December 31, 2008
Current:				
Federal	$ (4)	$ 32	$ 26	$ 37
State	1	5	4	4
Deferred:				
Federal – net	12	21	14	(2)
State – net	1	2	2	(2)
Investment tax credit – deferred	-	-	4	8
Amortization of investment tax credit	-	(2)	(3)	(4)
Total income tax expense	$ 10	$ 58	$ 47	41

In June 2006, LG&E and KU filed a joint application with the U.S. Department of Energy ("DOE") requesting certification to be eligible for an investment tax credit applicable to the construction of TC2. In November 2006, the DOE and the IRS announced that LG&E and KU 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, LG&E received an Order from the Kentucky Commission approving the accounting of the investment tax credit, which includes a full depreciation basis adjustment for the amount of the credit. LG&E's portion of the TC2 tax credit is approximately $24 million. Based on eligible construction expenditures incurred, LG&E recorded an investment tax credit of $4 million and $8 million in 2009 and 2008, respectively, decreasing current federal income taxes. As of December 31, 2009, LG&E had recorded its maximum credit of $24 million. The income tax expense impact from amortizing this credit over the life of the related property began when the facility was placed in service in January 2011.

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. The plaintiffs voluntarily dismissed their complaint in August 2010.

Components of deferred income taxes included in the Balance Sheets are shown below:

	Successor December 31, 2010	Predecessor December 31, 2009
Deferred income tax liabilities:		
Depreciation and other plant-related items	$ 423	$ 383
Regulatory assets and other	121	45
Pension and related benefits	16	2
Total deferred income tax liabilities	560	430
Deferred income tax assets:		
Regulatory liabilities and other	86	-
Investment tax credit	8	11
Income taxes due to customers	13	16
Liabilities and other	36	34
Total deferred income tax assets	143	61
Net deferred income tax liabilities	$ 417	$ 369
Balance sheet classification:		
Prepayments and other current assets	$ (2)	$ (4)
Deferred income taxes (non-current)	419	373
Net deferred income tax liabilities	$ 417	$ 369

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

A reconciliation of differences between the income tax expense at the statutory U.S. federal income tax rate and LG&E's actual income tax expense follows:

	Successor	Predecessor		
	November 1, 2010 through December 31, 2010	January 1, 2010 through October 31, 2010	Year Ended December 31, 2009	Year Ended December 31, 2008
Statutory federal income tax expense	$ 10	$ 58	$ 50	$ 46
State income taxes – net of federal benefit	1	4	4	1
Qualified production activities deduction	-	(2)	(1)	(1)
Amortization of investment tax credits	(1)	(2)	(3)	(4)
Other differences – net	-	-	(3)	(1)
Income tax expense	$ 10	$ 58	$ 47	$ 41
Effective income tax rate	34.5%	34.7%	33.1%	31.3%

The Tax Relief, Unemployment Reauthorization and Job Creation Act of 2010, enacted December 17, 2010 provided, among other provisions, certain incentives related to bonus depreciation and 100% expensing of qualifying capital expenditures. LG&E benefited from these new provisions by reducing its 2010 current federal income tax expense. This reduction in federal taxable income for LG&E does, however, result in a reduction of LG&E's Section 199 Manufacturing deduction, which is based on manufacturing taxable income and correspondingly increases income tax expense. The impact from these changes on 2010 was not material; however, LG&E anticipates a significant reduction of taxable income in 2011 and 2012 and a corresponding loss of most, if not all, of the Section 199 Manufacturing deduction for the following two years.

Note 11 - Long-Term Debt

As summarized below, at December 31, 2010, long-term debt consisted of first mortgage bonds and secured pollution control bonds. At December 31, 2009, long-term debt and the current portion of long-term debt consisted primarily of pollution control bonds and long-term loans from affiliated companies.

	Successor 2010	Predecessor 2009
Long-term debt to affiliated companies	$ -	$ 485
Secured first mortgage bonds, net of debt discount and amortization of debt discount	535	-
Pollution control revenue bonds, collateralized by first mortgage bonds	574	411
Fair value adjustment from purchase accounting	7	-
Unamortized discount	(4)	-
Total long-term debt	1,112	896
Less current portion	-	120
Long-term debt, excluding current portion	$ 1,112	$ 776

	Stated Interest Rates	Maturities	Debt Amounts
Successor			
Outstanding at December 31, 2010:			
Current portion	N/A	N/A	$ -
Non-current portion	Variable – 5.75%	2015-2040	1,112
Predecessor			
Outstanding at December 31, 2009:			
Current portion	Variable	2026-2027	$ 120
Non-current portion	Variable – 6.48%	2012-2037	776

As of December 31, 2009, long-term debt includes $120 million of pollution control bonds that were classified as current portion 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 Jefferson County 2001 Series A and B and Trimble County 2001 Series A and B. Maturity dates for these bonds range from 2026 to 2027. As of December 31, 2009, the bonds were classified as current portion of long-term debt because investors could put the bonds back to the Company within one year. As of December 31, 2010, the bonds were reclassified as long-term debt. See Note 1, Summary of Significant Accounting Policies, for changes in classification.

Pollution control bonds are obligations of LG&E issued in connection with tax-exempt pollution control bonds by various counties in Kentucky. A loan agreement obligates the Company to make debt service payments to the counties in amounts equal to the debt service due from the counties on the related pollution control bonds. Depending on the type of expense, the Successor capitalized debt expenses in long-term other regulatory assets or long-term other assets to align with the term of the debt to which the expenses were related. The Predecessor capitalized debt expenses in current or long-term other regulatory assets or other current or long-term other assets based on the amount of expense expected to be recovered within the next year through rate recovery. Both Predecessor and Successor amortized debt expenses over the lives of the related bond issues. The Predecessor presentation and the Successor presentation are both appropriate under regulatory practices and GAAP.

In October 2010, in order to secure their respective obligations with respect to the pollution control bonds, LG&E issued first mortgage bonds to the pollution control bond trustees. LG&E's first mortgage bonds contain terms and conditions that are substantially parallel to the terms and conditions of the counties' debt, but provide that obligations are deemed satisfied to the extent of payments under the related loan agreement, and thus generally require no separate payment of principal and interest except under certain circumstances, including should LG&E default on the respective loan agreement. Also in October 2010, one national rating agency revised downward the short-term credit rating of the pollution control bonds and the Company's issuer rating as a result of the pending acquisition by PPL.

Several series of LG&E's pollution control bonds are insured by monoline bond insurers whose ratings have been reduced due to exposures relating to insurance of sub-prime mortgages. At December 31, 2010, LG&E had an aggregate $574 million (including $163 million of reacquired bonds) of outstanding pollution control indebtedness, of which $135 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. Since 2008, interest rates increased and the Company experienced "failed auctions" when there were insufficient bids for the bonds. When a failed auction occurs, the interest rate is set pursuant to a formula stipulated in the indenture.

The average annualized interest rates on the auction rate bonds follow:

Successor	Predecessor	
November 1, 2010 through December 31, 2010	January 1, 2010 through October 31, 2010	Year Ended December 31, 2009
0.47%	0.43%	0.38%

The instruments governing these auction rate bonds permit LG&E 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.

As of December 31, 2010, LG&E continued to hold repurchased bonds in the amount of $163 million. As of December 31, 2009, the repurchased bonds were reported net by excluding from long-term debt. As of December 31, 2010, the accounting treatment changed and the repurchased bonds were reported gross by including in long-term debt). See Note 1, Summary of Significant Accounting Policies, for changes in classification. See Note 19, Subsequent Events, and Note 18, Available for Sale Debt Securities, for details regarding the remarketing of the repurchased bonds on January 13, 2011.

As a result of downgrades of the monoline insurers by all of the rating agencies to levels below that of the Company's rating, the debt ratings of the Company's insured bonds are all based on the Company's senior secured debt rating and are not influenced by the monoline bond insurer ratings.

Interest rate swaps are used to hedge certain underlying variable-rate debt obligations. The swaps exchange floating-rate interest payments for fixed rate interest payments to reduce the impact of interest rate changes on the pollution control bonds. As of December 31, 2010 and 2009, the Company had swaps with an aggregate notional value of $179 million. Beginning in the third quarter of 2010, the unrealized gains and losses of the interest rate swaps are included in a regulatory asset, which offsets the long-term derivative liabilities. See Note 5, Derivative Financial Instruments, for further information.

In connection with the PPL acquisition, on November 1, 2010, LG&E borrowed $485 million from a PPL subsidiary, in order to repay loans from a subsidiary of E.ON. LG&E used the net proceeds received from the sale of the first mortgage bonds to repay the debt owed to the PPL subsidiary arising from the borrowing.

In November 2010, LG&E issued first mortgage bonds totaling $535 million and used the proceeds to repay the loans from a PPL subsidiary mentioned above and for general corporate purposes. The first mortgage bonds were issued at a discount as described in the table below:

First Mortgage Bonds	Principal	Discount Price	First Mortgage Bonds Proceeds (a)
Series due 2015	$ 250	99.647%	$ 249
Series due 2040	285	98.912%	282
Total	$ 535		$ 531

(a) Before expenses other than discount to purchaser

The first mortgage bonds were issued by LG&E in accordance with the rules of Section 144A of the Securities Act of 1933. LG&E has entered into a registration rights agreement in which it has agreed to file a registration statement with the SEC relating to an offer to exchange the first mortgage bonds for publicly tradable securities having substantially identical terms. If ultimate registration and/or certain milestones are not completed by certain dates in mid- and late 2011, the Company has agreed to pay liquidated damages to the bondholders. The liquidated damages would total 0.25% per annum of the principal amount of the bonds for the first 90 days and 0.50% per annum of the principal amount thereafter until the conditions described above have been cured.

There were no redemptions or maturities of long-term debt for 2009. Redemptions and maturities of long-term debt for 2010 are summarized below:

Year	Description	Principal Amount	Rate	Secured/ Unsecured	Maturity
Successor					
2010	Due to PPL Investment Corp.	$ 485	4.33%-6.48%	Unsecured	2012-2037
2010	Due to E.ON affiliates	485	4.33%-6.48%	Unsecured	2012-2037

There were no issuances of long-term debt in 2009. Issuances of long-term debt for 2010 are summarized below:

Year	Description	Principal Amount	Rate	Secured/ Unsecured	Maturity
Successor					
2010	Due to PPL Investment Corp.	$ 485	4.33%-6.48%	Unsecured	2012-2037
2010	First mortgage bonds	250	1.625%	Secured	2015
2010	First mortgage bonds	285	5.125%	Secured	2040

As of December 31, 2010, all of the Company's long-term debt is secured by a first mortgage lien on substantially all of the real and tangible personal property of the Company located in Kentucky.

Long-term debt maturities for LG&E are shown in the following table:

2011	$ -
2012	-
2013	-
2014	-
2015	250
Thereafter	859
	$ 1,109

LG&E was in compliance with all debt covenants at December 31, 2010.

See Note 1, Summary of Significant Accounting Policies, for certain debt refinancing and associated transactions completed by LG&E in connection with the PPL acquisition, Note 2, Acquisition by PPL, for the adjustment made to the pollution control bonds to reflect fair value and Note 15, Related Party Transactions, for long-term debt payable to affiliates.

Note 12 - Notes Payable and Other Short-Term Obligations

Intercompany Revolving Line of Credit

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

	Total Money Pool Available	Amount Outstanding	Balance Available	Average Interest Rate
December 31, 2010, Successor	$ 400	$ 12	$ 388	0.25%
December 31, 2009, Predecessor	400	170	230	0.20%

LKE maintains revolving credit facilities totaling $300 million at December 31, 2010 and $313 million at December 31, 2009, to ensure funding availability for the money pool. At December 31, 2010, the LKE facility is with PPL Investment Corp. LKE pays PPL Investment Corp. an annual commitment fee based on the Utilities' current bond ratings on the unused portion of the commitment. At December 31, 2009, one facility, totaling $150 million, was with E.ON North America, Inc., while the remaining line, totaling $163 million, was with Fidelia, both affiliated companies of E.ON. The balances are as follows:

	Total Available	Amount Outstanding	Balance Available	Average Interest Rate
December 31, 2010, Successor	$ 300	$ -	$ 300	N/A
December 31, 2009, Predecessor	313	276	37	1.25%

Bank Revolving Line of Credit

As of December 31, 2010, the Company maintained a $400 million revolving line of credit with a group of banks maturing in December 2014. The revolving line of credit allows LG&E to issue letters of credit or borrow funds up to $400 million. Outstanding letters of credit reduce the facility's available borrowing capacity. The Company pays the banks an annual commitment fee based on current bond ratings on the unused portion of the commitment. At December 31, 2010, there was $163 million borrowed under this facility with an average interest rate of 2.27%. This credit agreement contains financial covenants requiring the borrower's debt to total capitalization ratio to not exceed 70%, as calculated pursuant to the credit agreement, and other customary covenants.

As of December 31, 2009, the Company maintained bilateral lines of credit with unaffiliated financial institutions totaling $125 million, maturing in June 2012. The Company paid the banks an annual commitment fee on the unused portion of the commitment. At December 31, 2009, there was no balance outstanding under any of these facilities. These facilities were terminated on November 1, 2010 in conjunction with the PPL acquisition.

LG&E was in compliance with all line of credit covenants at December 31, 2010.

See Note 1, Summary of Significant Accounting Policies, for certain debt refinancing and associated transactions completed by LG&E in connection with the PPL acquisition and Note 15, Related Party Transactions, for long-term debt payable to affiliates.

Note 13 - Commitments and Contingencies

Operating Leases

LG&E leases office space, office equipment, plant equipment, real estate, railcars, telecommunications and vehicles and accounts for these leases as operating leases. Total lease expense less amounts contributed by affiliated companies occupying a portion of the office space leased by the Company, was $6 million each for 2010, 2009 and 2008. The future minimum annual lease payments for operating leases for years subsequent to December 31, 2010, are shown in the following table:

2011	$	5
2012		4
2013		3
2014		3
2015		2
Thereafter		1
	$	18

Sale and Leaseback Transaction

The Company is a participant in a sale and leaseback transaction involving its 38% interest in two jointly owned CTs at KU's E.W. Brown generating station (Units 6 and 7). Commencing in December 1999, LG&E and KU entered into a tax-efficient, 18-year lease of the CTs. The Utilities 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 the Utilities had retained its ownership. The leasing transaction was entered into following receipt of required state and federal regulatory approvals. At December 31, 2010, the Balance Sheets included these assets at a value of $39 million, which is reflected in "Regulated utility plant, - electric and natural gas."

In case of default under the lease, the Company 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 LG&E and KU.

At December 31, 2010, the maximum aggregate amount of default fees or amounts was $7 million, of which LG&E would be responsible for 38% (approximately $3 million). The Company has made arrangements with LKE, via guarantee and regulatory commitment, for LKE to pay its full portion of any default fees or amounts.

Letters of Credit

LG&E has provided letters of credit as of December 31, 2010 and 2009, for off-balance sheet obligations totaling $3 million to support certain obligations related to landfill reclamation and letters of credit for off-balance sheet obligations totaling less than $1 million to support certain obligations related to workers' compensation.

Commodity Purchases

OVEC

LG&E has a contract for power purchases with OVEC, terminating in 2026, for various Mw capacities. LG&E holds a 5.63% investment interest in OVEC with 10 other electric utilities. LG&E is not the primary beneficiary; therefore, the investment is not consolidated into the Company's financial statements, but is recorded on the cost basis. OVEC is located in Piketon, Ohio, and owns and operates two coal-fired power plants, Kyger Creek Station in Ohio, and Clifty Creek Station in Indiana. LG&E is contractually entitled to 5.63% of OVEC's output, approximately 134 Mw of nameplate generation capacity. Pursuant to the OVEC power purchase contract, the Company may be conditionally responsible for a 5.63% pro-rata share of certain obligations of OVEC under defined circumstances. These contingent liabilities may include unpaid OVEC indebtedness as well as shortfall amounts in certain excess decommissioning costs and postretirement benefits other than pension. LG&E's contingent potential proportionate share of OVEC's December 31, 2010 outstanding debt was $78 million. Future obligations for power purchases from OVEC are demand payments, comprised of annual minimum debt service payments, as well as contractually required reimbursement of plant operating, maintenance and other expenses and are shown in the following table:

2011	$ 20
2012	22
2013	22
2014	23
2015	22
Thereafter	258
	$ 367

Coal and Natural Gas Purchase Obligations

LG&E has contracts to purchase coal, natural gas and natural gas transportation. Future obligations are shown in the following table:

2011	$ 334
2012	109
2013	112
2014	98
2015	100
Thereafter	36
	$ 789

Construction Program

LG&E had approximately $128 million of commitments in connection with its construction program at December 31, 2010.

In June 2006, LG&E entered into a construction contract regarding the TC2 project. The contract is generally in the form of a 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. During 2009 and 2010, LG&E received several contractual notices from the TC2 construction contractor asserting historical force majeure and excusable event claims for a number of adjustments to the contract price, construction schedule, commercial operations date, liquidated damages or other relevant provisions. In September 2010, LG&E and the construction contractor agreed to a settlement to resolve the force majeure and excusable event claims occurring through July 2010, under the TC2 construction contract, which settlement provided for a limited, negotiated extension of the contractual commercial operations date and/or relief from liquidated damage calculations. With limited exceptions the Company took care, custody and control of TC2 on January 22, 2011, and has dispatched the unit to meet customer demand since that date. LG&E and the contractor agreed to a further amendment of the construction agreement whereby the contractor will complete certain actions relating to identifying and completing any necessary modifications to allow operation of TC2 on all fuels in accordance with initial specifications prior to certain dates, and amending the provisions relating to liquidated damages. LG&E cannot currently estimate the ultimate outcome of these matters.

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. In September 2007, the Secretary of the Kentucky Environmental and Public Protection Cabinet issued a final Order upholding the permit. The environmental groups petitioned the EPA to object to the state permit and subsequent permit revisions. In determinations made in September 2008 and June 2009, the EPA rejected most of the environmental groups' claims but identified three permit deficiencies which the KDAQ addressed by revising the permit. In August 2009, the EPA issued an Order denying the remaining claims with the exception of two additional deficiencies which the KDAQ was directed to address. The EPA determined that the proposed permit subsequently issued by the KDAQ satisfied the conditions of the EPA Order although the agency recommended certain enhancements to the administrative record. In January 2010, the KDAQ issued a final permit revision incorporating the proposed changes to address the EPA objections. In March 2010, the Sierra Club submitted a petition to the EPA to object to the permit revision, which is now pending before the EPA. The Company believes that the final permit as revised should not have a material adverse effect on its financial condition or results of operations. However, until the EPA issues a final ruling on the pending petition and all applicable appeals have been exhausted, the Company cannot predict the final outcome of this matter.

Environmental Matters

The Company's operations are subject to a number of environmental laws and regulations 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. As indicated below and summarized at the conclusion of this section, evolving environmental regulations will likely increase the level of capital and operating and maintenance expenditures incurred by the Company during the next several years. Based upon prior regulatory precedent, the Company believes that many costs of complying with such pending or future requirements would likely be recoverable under the ECR or other potential cost-recovery mechanisms, but the Company can provide no assurance as to the ultimate outcome of such proceedings before the regulatory authorities.

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.

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 place in the interim. The remand of the CAIR results in some uncertainty with respect to certain other EPA or state programs and proceedings and the Utilities' compliance plans relating thereto due to the interconnection of the CAIR with such associated programs.

In January 2010, the EPA proposed a revised NAAQS for ozone which would increase the stringency of the standard. In addition, the EPA published final revised NAAQS standards for NO_2 and SO_2 in February 2010 and June 2010, respectively, which are more stringent than previous standards. Depending on the level of action determined necessary to bring local nonattainment areas into compliance with the revised NAAQS standards, LG&E's power plants are potentially subject to requirements for additional reductions in SO_2 and NOx emissions.

In July 2010, the EPA issued the proposed CATR, which serves to replace the CAIR. The CATR provides for a two-phase SO_2 reduction program with Phase I reductions due by 2012 and Phase II reductions due by 2014. The CATR provides for NOx reductions in 2012, but the EPA advised that it is studying whether additional NOx reductions should be required for 2014. The CATR is more stringent than the CAIR as it accelerates certain compliance dates and provides for only intrastate and limited interstate trading of emission allowances. In addition to its preferred approach, the EPA is seeking comment on an alternative approach which would provide for individual emission limits at each power plant. The EPA has announced that it will propose additional "transport" rules to address compliance with revised NAAQS standards for ozone and particulate matter which will be issued by the EPA in the future, as discussed below.

Hazardous Air Pollutants

As provided in 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 addition, in 2006, the Metro Louisville Air Pollution Control District adopted rules aimed at regulating additional hazardous air pollutants from sources including power plants.

In February 2008, a federal appellate court issued a decision vacating the CAMR. The EPA has entered into a consent decree requiring it to promulgate a utility Maximum Achievable Control Technology rule to replace the CAMR with a proposed rule due by March 2011 and a final rule by November 2011. Depending on the final outcome of the rulemaking, the CAMR could be replaced by new rules with different or more stringent requirements for reduction of mercury and other hazardous air pollutants. Kentucky has also repealed its corresponding state mercury regulations.

Acid Rain Program

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 Clean Air Act also contains 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 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 the 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. LG&E had previously installed FGD equipment on all of its generating units prior to the effective date of the acid rain program. LG&E's strategy for its Phase II SO_2 requirements, which commenced in 2000, is to use accumulated emission allowances to defer certain additional capital expenditures and continue to evaluate improvements to further reduce SO_2 emissions. LG&E believes its costs in reducing SO_2, NOx and mercury emissions to be comparable to those of similarly situated utilities with like generation assets. LG&E'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. LG&E will continue to monitor these developments to ensure that its environmental obligations are met in the most efficient and cost-effective manner. LG&E expects to incur additional capital expenditures currently approved in its ECR plans totaling approximately $100 million during the 2011 through 2013 time period to achieve emissions reductions and manage coal combustion residuals. Monthly recovery is subject to periodic review by the Kentucky Commission.

GHG Developments

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. As discussed below, 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, 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. The current administration has announced its support for the adoption of mandatory GHG reduction requirements at the federal level. The United States and other countries met in Copenhagen, Denmark, in December 2009, in an effort to negotiate a GHG reduction treaty to succeed the Kyoto Protocol, which is set to expire in 2013. In Copenhagen, the U.S. made a nonbinding commitment to, among other things, seek to reduce GHG emissions to 17% below 2005 levels by 2020 and provide financial support to developing countries. The United States and other nations met in Cancun, Mexico, in December 2010 to continue negotiations toward a binding agreement.

GHG Legislation

LG&E is monitoring on-going efforts to enact GHG reduction requirements and requirements governing carbon sequestration at the state and federal level and is assessing potential impacts of such programs and strategies to mitigate those impacts. In June 2009, the U.S. House of Representatives passed the American Clean Energy and Security Act of 2009, which was a comprehensive energy bill containing the first-ever nation-wide GHG cap and trade program. The bill provided for reductions in GHG emissions of 3% below 2005 levels by 2012, 17% by 2020 and 83% by 2050. In order to cushion potential rate impacts for utility customers, approximately 43% of emissions allowances would have initially been allocated at no cost to the electric utility sector, with this allocation gradually declining to 7% in 2029 and zero thereafter. The bill would have also established a renewable electricity standard requiring utilities to meet 20% of their electricity demand through renewable energy and energy efficiency by 2020. The bill contained additional provisions regarding carbon capture and sequestration, clean transportation, smart grid advancement, nuclear and advanced technologies and energy efficiency.

In September 2009, the Clean Energy Jobs and American Power Act, which was largely patterned on the House legislation, was introduced in the U.S. Senate. The Senate bill raised the emissions reduction target for 2020 to 20% below 2005 levels and did not include a renewable electricity standard. While the initial bill lacked detailed provisions for the allocation of emissions allowances, a subsequent revision incorporated allowance allocation provisions similar to the House bill. Although Senators Kerry and Lieberman and others worked to reach a consensus on GHG legislation, no bill passed the Senate in 2010. The Company is closely monitoring the progress of pending energy legislation, but the prospect for passage of comprehensive GHG legislation in 2011 is uncertain.

GHG Regulations

In April 2007, the U.S. Supreme Court ruled that the EPA has the authority to regulate GHG under the Clean Air Act. In April 2009, the EPA issued a proposed endangerment finding concluding that GHGs endanger public health and welfare, which is an initial rulemaking step under the Clean Air Act. A final endangerment finding was issued in December 2009. In September 2009, the EPA issued a final GHG reporting rule requiring reporting by facilities with annual GHG emissions equivalent to at least 25,000 tons of carbon dioxide. A number of the Company's facilities are required to submit annual reports commencing with calendar year 2010. In May 2010, the EPA issued a final GHG "tailoring" rule, effective January 2011, requiring new or modified sources with GHG emissions equivalent to at least 75,000 tons of carbon dioxide to obtain permits under the Prevention of Significant Deterioration Program. Such new or modified facilities would be required to install Best Available Control Technology. While the Company is unaware of any currently available GHG control technology that might be required for installation on new or modified power plants, it is currently assessing the potential impact of the rule. The final rule will apply to new and modified power plants beginning in January 2011. The Company is unable to predict whether mandatory GHG reduction requirements will ultimately be enacted through legislation or regulations. In December 2010, the EPA announced that it plans to promulgate GHG New Source Performance Standards for power plants, including both new and existing facilities. A proposed rule is expected by July 2011, while a final rule is expected by May 2012. In the absence of either a proposed or final regulation, LG&E is unable to assess the potential impact of any future regulation.

GHG Litigation

A number of lawsuits have been filed asserting common law claims including nuisance, trespass and negligence against various companies with GHG emitting facilities. In October 2009, a three-judge panel of the United States Court of Appeals for the 5th Circuit in the case of Comer v. Murphy Oil reversed a lower court, holding that private plaintiffs have standing to assert certain common law claims against more than 30 utility, oil, coal and chemical companies. In March 2010, the court vacated the opinion of the three-judge panel and granted a motion for rehearing but subsequently denied the appeal due to the lack of a quorum. The appellate ruling leaves in effect the lower court ruling dismissing the plaintiffs' claims. In January 2011, the Supreme Court denied petitioner's petition for review, which effectively brings the case to an end. The Comer complaint alleged that GHG emissions from the defendants' facilities contributed to global warming which increased the intensity of Hurricane Katrina. E.ON, the former indirect parent of the Utilities, was named as a defendant in the complaint but was not a party to the proceedings due to the failure of the plaintiffs to pursue service under the applicable international procedures. LG&E continues to monitor relevant GHG litigation to identify judicial developments that may be potentially relevant to operations.

Ash Ponds and Coal-Combustion Byproducts

The EPA has undertaken various initiatives in response to the December 2008 impoundment failure at the TVA's Kingston power plant, which resulted in a major release of coal combustion byproducts into the environment. The EPA issued information requests to utilities throughout the country, including LG&E, to obtain information on their ash ponds and other impoundments. In addition, the EPA inspected a large number of impoundments located at power plants to determine their structural integrity. The inspections included several of LG&E's impoundments, which the EPA found to be in satisfactory condition except for certain impoundments at the Mill Creek and Cane Run stations, which were determined to be in fair condition. In June 2010, the EPA published proposed regulations for coal combustion byproducts handled in landfills and ash ponds. The EPA has proposed two alternatives: (1) regulation of coal combustion byproducts in landfills and ash ponds as a hazardous waste or (2) regulation of coal combustion byproducts as a solid waste with minimum national standards. Under both alternatives, the EPA has proposed safety requirements to address the structural integrity of ash ponds. In addition, the EPA will consider potential refinements of the provisions for beneficial reuse of coal combustion byproducts.

Water Discharges and PCB Regulations

The EPA has also announced plans to develop revised effluent limitation guidelines governing discharges from power plants and standards for cooling water intake structures. The EPA has further announced plans to develop revised standards governing the use of polychlorinated biphenyls ("PCB") in electrical equipment. The Company is monitoring these ongoing regulatory developments but will be unable to determine the impact until such time as new rules are finalized.

Impact of Pending and Future Environmental Developments

As a company with significant coal-fired generating assets, LG&E will likely be substantially impacted by pending or future environmental rules or legislation requiring mandatory reductions in GHG emissions or other air emissions, imposing more stringent standards on discharges to waterways, or establishing additional requirements for handling or disposal of coal combustion byproducts. These evolving environmental regulations will likely require an increased level of capital expenditures and increased incremental operating and maintenance costs by the Company over the next several years. Due to the uncertain nature of the final regulations that will ultimately be adopted by the EPA, including the reduction targets and the deadlines that will be applicable, the Company cannot finalize estimates of the potential compliance costs, but should the final rules incorporate additional emission reduction requirements, require more stringent emissions controls or implement more stringent byproducts storage and disposal practices, such costs will likely be significant. With respect to NAAQS, CATR, CAMR replacement and coal combustion byproducts developments, based upon a preliminary analysis of proposed regulations, the Company may be required to consider actions such as upgrading existing emissions controls, installing additional emissions controls, upgrading byproducts disposal and storage and possible early replacement of coal-fired units. Capital expenditures for LG&E associated with such actions are preliminarily estimated to be in the $1.5 to $1.8 billion range over the next ten years, although final costs may substantially vary. With respect to potential developments in water discharge, revised PCB standards or GHG initiatives, costs in such areas cannot be estimated due to the preliminary status or uncertain outcome of such developments, but would be in addition to the above amount and could be substantial. Ultimately, the precise impact on the Company's operations of these various environmental developments cannot be determined prior to the finalization of such requirements. Based upon prior regulatory precedent, the Company believes that many costs of complying with such pending or future requirements would likely be recoverable under the ECR or other potential cost-recovery mechanisms, but the Company can provide no assurance as to the ultimate outcome of such proceedings before the regulatory authorities.

TC2 Water Permit

In May 2010, the Kentucky Waterways Alliance and other environmental groups filed a petition with the Kentucky Energy and Environment Cabinet challenging the Kentucky Pollutant Discharge Elimination System permit issued in April 2010, which covers water discharges from the Trimble County generating station. In October 2010, the hearing officer issued a report and recommended Order providing for dismissal of the claims raised by the petitioners. In December 2010, the Secretary issued a final Order dismissing all claims and upholding the permit which petitioners subsequently appealed to Trimble County Circuit Court.

General Environmental Proceedings

From time to time, LG&E 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 a prior Section 114 information request from the EPA relating to new source review issues at LG&E's Mill Creek Unit 4 and TC1; remediation obligations or activities for former manufactured gas plant sites or 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 on-going claims regarding alleged particulate emissions from the Company's Cane Run generating station and claims regarding GHG emissions from the Company's generating stations. With respect to the former manufactured gas plant sites, LG&E has estimated that it could incur additional costs of less than $1 million for remaining clean-up activities under existing approved plans or agreements. Based on analysis to date, the resolution of these matters is not expected to have a material impact on the Company's operations.

Note 14 - Jointly Owned Electric Utility Plant

<u>Trimble County Unit 1</u>

The Company owns a 75% undivided interest in TC1 which the Kentucky Commission has allowed to be reflected in customer rates. Of the remaining 25% of the unit, IMEA owns a 12.12% undivided interest and IMPA owns a 12.88% undivided interest. Each company is responsible for its proportionate ownership share of fuel cost, operation and maintenance expenses and incremental assets.

The following data represent shares of the jointly owned property (capacity based on nameplate rating):

	TC1			
	LG&E	IMPA	IMEA	Total
Ownership interest	75%	12.88%	12.12%	100%
Mw capacity	425	73	68	566

LG&E's 75% ownership:	
Cost	$ 288
Construction work in progress	17
Accumulated depreciation	(9)
Net book value	$ 296

Trimble County Unit 2

TC2 is a jointly owned unit at the Trimble County site. LG&E and KU own undivided 14.25% and 60.75% interests, respectively. Of the remaining 25%, 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 is in-service. With limited exceptions the Company took care, custody and control of TC2 on January 22, 2011, and has dispatched the unit to meet customer demand since that date. LG&E and the contractor agreed to a further amendment of the construction agreement whereby the contractor will complete certain actions relating to identifying and completing any necessary modifications to allow operation of TC2 on all fuels in accordance with initial specifications prior to certain dates, and amending the provisions relating to liquidated damages.In December 2009 and June 2008, LG&E sold assets to KU related to the construction of TC2 with a net book value of $48 million and $10 million, respectively.

	TC2				
	LG&E	KU	IMPA	IMEA	Total
Ownership interest	14.25%	60.75%	12.88%	12.12%	100%
Mw capacity	119	509	108	102	838

LG&E's 14.25% ownership:	
Plant held for future use	$ 2
Construction work in progress	187
Accumulated depreciation	-
Net book value	$ 189

KU's 60.75% ownership:	
Plant held for future use	$ 62
Construction work in progress	703
Accumulated depreciation	(1)
Net book value	$ 764

LG&E and KU jointly own the following CTs and related equipment (capacity based on net summer capability) as of December 31, 2010:

	LG&E				KU				Total			
Ownership Percentage	Mw Capacity	Cost	Depr.	Net Book Value	Mw Capacity	Cost	Depr.	Net Book Value	Mw Capacity	Cost	Depr.	Net Book Value
KU 47%, LG&E 53% (a)	146	$ 48	$ -	$ 48	129	$ 43	$ -	$ 43	275	$ 91	$ -	$ 91
KU 62%, LG&E 38% (b)	118	40	(2)	38	190	64	(2)	62	308	104	(4)	100
KU 71%, LG&E 29% (c)	92	26	-	26	228	63	(1)	62	320	89	(1)	88
KU 63%, LG&E 37% (d)	236	64	(1)	63	404	109	(1)	108	640	173	(2)	171
KU 71%, LG&E 29% (e)	n/a	2	-	2	n/a	4	-	4	n/a	6	-	6

(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 10 Mw of capacity for LG&E.
(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 LG&E's and KU's participating share of direct expenses of the jointly owned plants is included in the corresponding operating expenses on each company's respective Statements of Income, (i.e., fuel, maintenance of plant, other operating expense).

Note 15 - Related Party Transactions

LG&E and subsidiaries of LKE and PPL engage in related party transactions. Transactions between LG&E and LKE subsidiaries are eliminated on consolidation of LKE. Transactions between LG&E and PPL subsidiaries are eliminated on consolidation of PPL. These transactions are generally performed at cost and are in accordance with FERC regulations under PUHCA 2005 and the applicable Kentucky Commission regulations.

<u>Intercompany Wholesale Sales and Purchases</u>

LG&E and KU jointly dispatch their generation units with the lowest cost generation used to serve their retail native load. When LG&E has excess generation capacity after serving its own retail native load and its generation cost is lower than that of KU, KU purchases electricity from LG&E. When KU has excess generation capacity after serving its own retail native load and its generation cost is lower than that of LG&E, LG&E purchases electricity from KU. These transactions are recorded as intercompany wholesale sales and purchases are recorded by each company at a price equal to the seller's fuel cost. Savings realized from purchasing electricity intercompany instead of generating from their own higher costs units or purchasing from the market are shared equally between the Utilities. The volume of energy each company has to sell to the other is dependent on its native load needs and its available generation.

These sales and purchases are included in the Statements of Income as "Operating revenues", "Power purchased" expenses and "Other operation and maintenance expenses". LG&E's intercompany electric revenues and power purchased expenses were as follows:

	Successor	Predecessor		
	November 1, 2010 through December 31, 2010	January 1, 2010 through October 31, 2010	Year Ended December 31,	
			2009	2008
Electric operating revenues from KU	$ 21	$ 79	$ 101	$ 109
Power purchased and related operations and maintenance expenses from KU	2	13	21	80

Interest Charges

See Note 11, Long-Term Debt, and Note 12, 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.

LG&E's interest expense to affiliated companies was as follows:

	Successor	Predecessor		
	November 1, 2010 through December 31, 2010	January 1, 2010 through October 31, 2010	Year Ended December 31,	
			2009	2008
Interest on money pool loans	$ -	$ -	$ 1	$ 6
Interest on PPL loans	1	-	-	-
Interest on Fidelia loans	-	22	27	23

Interest paid to LKE on the money pool arrangement was less than $1 million for 2010 and 2009.

Dividends

In March and September 2010, the Company paid dividends of $30 million and $25 million, respectively, to its sole shareholder, LKE. The Company also paid dividends of $80 million and $40 million to LKE in 2009 and 2008, respectively.

Capital Contributions

The Company received no capital contributions in 2010 or 2009, but received a capital contribution of $20 million from its sole shareholder, LKE, in December 2008.

Sale of Assets

In 2010, LG&E sold and bought assets of less than $1 million to and from KU. In December 2009, LG&E sold assets to KU related to the construction of TC2 with a net book value of $48 million.

Other Intercompany Billings

Servco provides the Company with a variety of centralized administrative, management and support services. Associated charges include payroll taxes paid by Servco on behalf of LG&E, labor and burdens of Servco employees performing services for LG&E, coal purchases and other vouchers paid by Servco on behalf of LG&E. The cost of these services is directly charged to the Company, 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/or other statistical information. These costs are charged on an actual cost basis.

In addition, the Utilities provide services to each other and to Servco. Billings between the Utilities relate to labor and overheads associated with union and hourly employees performing work for the other utility, charges related to jointly-owned generating units and other miscellaneous charges. Billings from LG&E to Servco include cash received by Servco on behalf of LG&E, tax settlements and other payments made by the Company on behalf of other non-regulated businesses which are reimbursed through Servco.

Intercompany billings to and from LG&E were as follows:

	Successor	Predecessor		
	November 1, 2010 through December 31, 2010	January 1, 2010 through October 31, 2010	Year Ended December 31, 2009	Year Ended December 31, 2008
Servco billings to LG&E	$ 40	$ 216	$ 181	$ 206
KU billings to LG&E	-	-	78	75
LG&E billings to Servco	8	16	1	5
LG&E billings to KU	14	49	44	5

Intercompany Balances

The Company had the following balances with its affiliates:

	Successor	Predecessor
	December 31, 2010	December 31, 2009
Accounts receivable from KU	$ 22	$ 53
Accounts receivable from LKE	8	-
Accounts payable to Servco	20	18
Accounts payable to LKE	-	4
Accounts payable to Fidelia	-	6
Notes payable to LKE	12	170
Long-term debt to Fidelia	-	485

Note 16 - Selected Quarterly Data (Unaudited)

	For the 2010 Periods Ended (a)				
	Predecessor				Successor
	March 31	June 30	September 30	October 31	December 31
Operating revenues	$ 366	$ 27	$ 327	$ 85	$ 254
Operating income	64	43	77	4	40
Net income	33	14	60	2	19

(a) Periods ended March 31, June 30 and September 30 represent three months then ended. Period ended October 31 represents one month then ended and period ended December 31 represents two months then ended.

	For the 2009 Quarters Ended			
	Predecessor			
	March 31	June 30	September 30	December 31
Operating revenues	$ 428	$ 277	$ 276	$ 291
Operating income	12	33	94	28
Net income	5	21	50	19

Note 17 - Accumulated Other Comprehensive Income (Loss)

Accumulated other comprehensive loss consisted of the following:

	Pre-Tax Accumulated Derivative Gain (Loss)	Income Taxes	Net
Balance at December 31, 2007, Predecessor	$ (20)	$ 8	$ (12)
Gains (losses) on derivative instruments designated and qualifying as cash flow hedging instruments	(2)	-	(2)
Balance at December 31, 2008, Predecessor	$ (22)	$ 8	$ (14)
Gains (losses) on derivative instruments designated and qualifying as cash flow hedging instruments	5	(1)	4
Balance at December 31, 2009, Predecessor	$ (17)	$ 7	$ (10)
Gains (losses) on derivative instruments designated and qualifying as cash flow hedging instruments	17	(7)	10
Balance at October 31, 2010, Predecessor	$ -	$ -	$ -
Gains (losses) on derivative instruments designated and qualifying as cash flow hedging instruments	-	-	-
Balance at December 31, 2010, Successor	$ -	$ -	$ -

Note 18 - Available for Sale Debt Securities

LG&E's available for sale debt securities include the following pollution control bonds, which were repurchased from the remarketing agent in 2008:

	December 31 2010	December 31 2009
Louisville Metro 2003 Series A, due October 1, 2033, variable %	$ 128	$ -
Louisville Metro 2007 Series B, due June 1, 2033, variable %	35	-
	$ 163 (a)	$ - (b)

(a) No realized or unrealized gains (losses) were recorded on these securities as the difference between the carrying value and the fair value was insignificant.
(b) Prior to the PPL acquisition, repurchased bonds were not accounted for as "Available for sale debt securities" and were presented on a net basis on the Balance Sheets. See Note 1, Summary of Significant Accounting Policies, and Note 11, Long-Term Debt, for further discussion.

In January 2011, LG&E remarketed these bonds to unaffiliated investors. See Note 19, Subsequent Events, for further discussion regarding the remarketing of these bonds.

Note 19 - Subsequent Events

Subsequent events have been evaluated through February 25, 2011, the date of issuance of these statements. These statements contain all necessary adjustments and disclosures resulting from that evaluation.

With limited exceptions the Company took care, custody and control of TC2 on January 22, 2011, and has dispatched the unit to meet customer demand since that date. LG&E and KU and the contractor agreed to a further amendment of the construction agreement whereby the contractor will complete certain actions relating to identifying and completing any necessary modifications to allow operation of TC2 on all fuels in accordance with initial specifications prior to certain dates, and amending the provisions relating to liquidated damages.

On January 14, 2011, LG&E contributed $64 million to its pension plans.

On January 13, 2011, LG&E remarketed the Louisville/Jefferson County Metro Government 2003 Series A and 2007 Series B bonds, having $128 million and $35 million in outstanding principal amount, respectively, which bonds had been previously repurchased by LG&E and shown in "Available for sale debt securities" on the Balance Sheets. In connection with the remarketing, each bond series was converted to a mode wherein the interest rate is fixed for an intermediate term but not the full term of the bond. The bonds will bear interest at the rate of 1.90% each, until April 2012 and June 2012, in the case of the 2003 Series A and 2007 Series B bonds, respectively. At the end of the intermediate term, the Company must remarket the bonds or buy them back. As of January 13, 2011, LG&E had no remaining repurchased bonds. LG&E used the proceeds from the remarketed bonds to repay the balance of its credit facility.

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Report of Independent Auditors

To Stockholder of Louisville Gas and Electric Company

In our opinion, the accompanying balance sheet and the related statements of income, retained earnings, comprehensive income, cash flows, and capitalization present fairly, in all material respects, the financial position of Louisville Gas and Electric Company (Successor Company) at December 31, 2010 and the results of its operations and its cash flows for the period from November 1, 2010 to December 31, 2010 in conformity with accounting principles generally accepted in the United States of America. Also in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2010, based on criteria established in *Internal Control - Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). The Company's management is responsible for these financial statements, for maintaining effective internal control over financial reporting and for its assertion of the effectiveness of internal control over financial reporting, included in "Management's Report of Internal Controls Over Financial Reporting " which appears on page 54. Our responsibility is to express opinions on these financial statements and on the Company's internal control over financial reporting based on our integrated audit. We conducted our audit in accordance with the standards of the Public Company Accounting Oversight Board (United States) and in accordance with the auditing and attestation standards established by the American Institute of Certified Public Accountants. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement and whether effective internal control over financial reporting was maintained in all material respects. Our audit of the financial statements included 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. Our audit of internal control over financial reporting included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audit also included performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinions.

As discussed in Note 2 to the financial statements, on November 1, 2010, PPL Corporation completed its acquisition of LG&E and KU Energy LLC and its subsidiaries. The push-down basis of accounting was used to at the acquisition date.

A company's internal control over financial reporting is a process effected by those charged with governance, management, and other personnel, designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial

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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 (i) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (ii) 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 those charged with governance and (iii) provide reasonable assurance regarding prevention or timely detection and correction 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 and correct 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.

PricewaterhouseCoopers LLP

Louisville, Kentucky
February 25, 2011

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Report of Independent Auditors

To Stockholder of Louisville Gas and Electric Company

In our opinion, the accompanying balance sheet and the related statements of income, retained earnings, comprehensive income, cash flows, and capitalization present fairly, in all material respects, the financial position of Louisville Gas and Electric Company (Predecessor Company) at December 31, 2009 and the results of its operations and its cash flows for the period from January 1, 2010 to October 31, 2010 and for each of the two years in the period ended December 31, 2009 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 generally accepted auditing standards as established by the Auditing Standards Board (United States) and in accordance with the auditing standards of the Public Company Accounting Oversight Board (United States). 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, on November 1, 2010, PPL Corporation completed its acquisition of LG&E and KU Energy LLC and its subsidiaries. The push-down basis of accounting was used at the acquisition date.

PricewaterhouseCoopers LLP

Louisville, Kentucky
February 25, 2011

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TRANSFER OF ASSETS

In 2010, Louisville Gas and Electric Company (LG&E) transferred circuit breaker and transformer equipment to Kentucky Utilities (KU) with values of $71,305.28 and $2,250.00, respectively. Also in 2010, KU transferred construction equipment to LG&E with a value of $93,248.00.

INTERCOMPANY MONTHLY INVOICES

Monthly invoices are prepared for reimbursement of non-fuel related expenses incurred by LG&E or KU for LG&E, KU, LG&E and KU Services Company (Servco), LG&E and KU Energy LLC (LKE) and subsidiaries. The invoices are provided to Servco, LKE, and subsidiaries by the 10th business day of the subsequent month with payment due by the 13th business day of the month. The invoices and cash disbursement requests related to fuel and fuel-related products are prepared for reimbursement on the 15th and 25th day of the month, or the following business day. All billings between the regulated utilities (LG&E/KU) and non-regulated entities (Servco/LKE) are billed and settled on a net basis.

In addition to the invoices, summary transaction listings are provided as supporting documentation of the expenses on each billing. A system-generated process from the Oracle General Ledger system provides the summary of the transactions that resulted in automatic intercompany transactions among companies. For fuel and fuel-related product transactions, a report from Fuelworx, the Fuels Management System, provides a summary of the transactions that resulted in automatic intercompany transactions between the companies. Monthly reconciliation and balancing procedures are currently in place for all entities receiving and providing intercompany charges to ensure the accuracy of such transactions.

INTERCOMPANY POWER SALES AND PURCHASES

Monthly journal entries are prepared for off-system sales, off-system and native load purchases, and intercompany power sales and purchases between LG&E and KU. The After-the-Fact Billing system (AFB) is used to stack hourly energy, which allocates energy sources (generation and purchased power) to energy sinks (KU native load, LG&E native load and off-system sales (OSS)). The stacking is performed based on the energy cost where lowest cost energy is allocated to native load and highest cost energy is allocated to OSS, consistent with the companies' Power Supply System Agreement.

Outputs from the AFB program (queries) are used as inputs into an Excel spreadsheet. The spreadsheet calculates the allocation of third party and intercompany purchases between LG&E and KU. It also calculates the split between native load and off-system purchases, and uses the generation expenses for both companies to calculate the allocation of OSS between the companies.

MARGIN ACCOUNT ALLOCATION

Each month LG&E and KU participate in the purchase of forward financial power transactions with MF Global. As these transactions are either settled or re-valued throughout the month, the margin collateral requirements change accordingly. At the end of each month, the increase or decrease to the Margin Cash Account (as well as the expense and income) is split between the two companies. The settled swap portion of the Margin Cash Account is allocated based on the split of the generation expenses for LG&E and KU, as determined by AFB (After-the-Fact Billing). AFB is the system used to stack hourly energy, which is allocated energy sources (generation and purchased power) to energy sinks (KU native load, LG&E native load, and off-system sales (OSS)). The stacking is performed based on the energy cost where lowest cost energy is allocated to native load and highest cost energy is allocated to OSS. The unsettled swap portion of the Margin Cash Account (or Mark-to-Market) is allocated based on the forward 12 month rolling forecasted average of the split of the generation expenses for LG&E and KU.

COSTS OF JOINTLY OWNED TRIMBLE COUNTY UNIT 2

The charges for the construction of Trimble County Unit 2 (TC2) are allocated among the joint owners, LG&E, KU, Illinois Municipal Electric Agency (IMEA) and Indiana Municipal Power Agency (IMPA). IMEA and IMPA have a combined 25% interest in the ownership of TC2. IMEA and IMPA are billed 25% of the amounts allocated to both KU and LG&E in the current month. The actual capital costs for TC2 are booked in the current month through either the Accounts Payable system or manual accruals, depending on the timing of the invoices submitted. TC2 accruals are received from the Project Engineering department, posted and reversed in the subsequent month. True-up of actual costs are performed on a quarterly basis to ensure that all allocation percentages are correct.

Assets constructed only for use at TC2 are allocated according to the 19% LG&E, 81% KU contractual split. Assets that will be used for both TC2 and Trimble County Unit 1 (TC1), the existing coal-fired generating unit at the Trimble County facility, are allocated based on the respective nameplate ratings (52% to LG&E and 48% to KU). Charges allocated to TC1 are recorded 100% to LG&E.

ALLOCATION OF BUILDING RENT

Expenses incurred for renting a portion of the LG&E Center are billed to affiliates of Louisville Gas and Electric for the occupation of office space by employees of Kentucky Utilities and LG&E and KU Services Company.

The monthly allocation of rent expense for the LG&E Center is based on a levelized amortization of the total value of the rent payments. The operation and maintenance portion of the accrual is based on a monthly charge which is billed to LG&E by Louisville Financial Associates, LLC.

The allocation to LG&E, KU, Servco, and LKE and subsidiaries is based on net labor expense from the prior year for LG&E, KU, Servco, and LKE and subsidiaries' employees occupying the second floor, floors four through sixteen, and common areas for which LG&E is billed.

EXPENSES OF JOINTLY OWNED COMBUSTION TURBINES

LG&E and KU jointly own ten combustion turbines (CT) located at the Paddy's Run facility, Trimble County Generating Station, and E.W. Brown facility. All operations and maintenance expenses attributable to the Paddy's Run, Trimble County, and E.W. Brown CTs are accumulated and billed according to the percentage of ownership. The percentage of ownership and megawatt capacity is listed in the table below (capacity based on net summer capability).

Facility	MW Capacity	LG&E	KU
Paddy's Run 13	158	53%	47%
Trimble County 5	160	29%	71%
Trimble County 6	160	29%	71%
Trimble County 7	160	37%	63%
Trimble County 8	160	37%	63%
Trimble County 9	160	37%	63%
Trimble County 10	160	37%	63%
E.W. Brown 5	117	53%	47%
E.W. Brown 6	154	38%	62%
E.W. Brown 7	154	38%	62%

Automated allocations are processed in the Oracle General Ledger system and generate intercompany transactions between LG&E and KU. All transactions flow through the intercompany receivable account. The costs for the Paddy's Run and Trimble County CTs are accumulated in LG&E and transferred to KU per the ownership percentage. The costs for the E.W. Brown CTs are accumulated in KU and transferred to LG&E per the ownership percentage.

When costs are accumulated in LG&E and transferred to KU, an intercompany receivable is debited and the appropriate expense is credited. KU debits the appropriate expense account and credits an intercompany receivable. When costs are accumulated in KU and transferred to LG&E, an intercompany receivable is debited and the appropriate expense is credited. LG&E debits the appropriate expense account and credits an intercompany receivable. The amounts are then netted to establish an intercompany receivable for KU or LG&E and an intercompany payable for LG&E or KU.

Additionally, manual journal entries are prepared each month for the applicable portion of the gas used by the CTs. The journal entries split the gas cost between LG&E and KU based on the percentage of ownership.

CASH COLLECTED AND PAID BY LG&E ON BEHALF OF KU

For the convenience of our suppliers and customers for purchased power and off system sales, and due to generating units being jointly dispatched, KU and LG&E have combined their billing and payments. This gives the appearance of one company to customers and suppliers.

Internally, sales and purchases are split between KU and LG&E and each company records its payable and receivable to the appropriate account. This split is documented on a monthly spreadsheet from the Revenue Accounting and Analysis department.

As LG&E makes payments to various vendors for purchased power, the disbursement request is split into the appropriate portions applicable to each company. LG&E issues the payment through its Accounts Payable Department and bills KU for the expenditures made on behalf of KU. The Oracle General Ledger system automatically creates the Intercompany payable and receivable as transactions are posted. The amount KU owes LG&E is included on the Intercompany billing from LG&E.

As LG&E receives payments for power sales, the money received is split into the appropriate amounts for each company and a monthly journal entry for the cash received on behalf of KU is recorded to create a payable to KU.

As payments are received by LG&E (KU) for off system sales, some of the same customers may have sold power to LG&E (KU). For the customers' convenience, when the contract allows, the payments are netted. Netted payments are booked by each utility as the gross amount of the receivable and payable so that cash received by LG&E (KU) reflects what was owed as both an Intercompany receivable and an Intercompany payable.

In addition, certain other receivables and payables which benefit both LG&E and KU are processed through only one of the companies for convenience or efficiency. The cash received and disbursement requests are split into the appropriate portions applicable to each company.

Intercompany receivables and payables are billed on the normal billing to the respective company and settled on the 13th business day of the month following the transaction. See Tab 3 for a description of the intercompany monthly invoices.

Intercompany interest is calculated for these transactions that are paid/held and settled through Intercompany in compliance with service agreements. Interest is calculated on a daily-accumulated balance of monies received and paid by LG&E on behalf of KU. Interest is calculated from the day the money is received or paid through the day of the Intercompany cash settlement. The interest rate is a 360-day Goldman Sachs rate, which is supplied by Treasury. A monthly journal entry is created to book the interest receivable/payable from this calculation.

E.ON U.S. SERVICES INC.

Cost Allocation Manual

E.ON U.S. Services Inc.
Cost Allocation Manual

CAM	Cost Allocation Manual
Capital Corp.	E.ON U.S. Capital Corp.
CCS	Customer Care System
EMS	Energy Management System
E.ON	E.ON AG
E.ON U.S.	E.ON U.S. LLC
E.ON U.S. Foundation	E.ON U.S. Foundation Inc.
FERC	Federal Energy Regulatory Commission
HR	Human Resources
IT	Information Technology
KPSC	Kentucky Public Service Commission
KU	Kentucky Utilities Company
LEM	LG&E Energy Marketing Inc.
LG&E	Louisville Gas and Electric Company
PUHCA 2005	Public Utility Holding Company Act of 2005
SEC	U.S. Securities and Exchange Commission
Servco	E.ON U.S. Services Inc.
VSCC	Virginia State Corporation Commission

E.ON U.S. Services Inc.
Cost Allocation Manual

Table of Contents

I. INTRODUCTION

PUHCA 2005 states that centralized service companies must maintain and make available to the FERC their books, accounts and other records in the specific manner and preserve them for the required periods as the FERC prescribes in Title 18 Code of Federal Regulations Part 368 of the FERC Uniform System of Accounts. These records must be in sufficient detail to permit examination, audit, and verification, as necessary and appropriate for the protection of utility customers with respect to jurisdictional rates. The purpose of this CAM is to document the methods, policies and procedures that Servco will follow in performing certain services for affiliate companies. In developing this CAM the overriding goal was to protect investors and consumers by ensuring the methods, policies and procedures contained in this CAM were PUHCA 2005 compliant so that Servco costs are fully segregated, and fairly and equitably allocated among the affiliate companies. Servco was authorized to conduct business as a service company for E.ON U.S. (formerly LG&E Energy LLC) and its various subsidiaries and affiliates by order of the SEC on December 6, 2000, and commenced operations January 1, 2001. E.ON U.S. is a Kentucky limited liability company and the parent of KU and LG&E. KU and LG&E are subject to the jurisdiction of and oversight by the KPSC. In addition, KU is subject to the jurisdiction of and oversight by the VSCC and the Tennessee Regulatory Authority. Under Kentucky regulatory law, KU and LG&E are required to have a cost allocation manual on file with the KPSC. KU is required to have a services agreement for any affiliate transaction approved by the VSCC prior to the transaction.

Periodic changes to the CAM may be necessary due to future management decisions, changes in the law, interpretations by state or federal regulatory bodies, changes in structure or activities of affiliates, or other internal procedures.

II. CORPORATE ORGANIZATION

OVERVIEW

E.ON U.S. and its utility subsidiaries are engaged principally in the generation, transmission, distribution and sale of electricity. LG&E is also engaged in the storage, distribution, and sale of natural gas. E.ON U.S. and its subsidiaries are subject to the regulatory provisions of PUHCA 2005. LG&E and KU are subject to regulation by the FERC the Kentucky Public Service Commission. KU is also subject to regulation by state utility commissions in Virginia and Tennessee.

E.ON U.S. has four direct subsidiaries: LG&E, KU, LEM, and Capital Corp. E.ON U.S. has an affiliate relationship with E.ON U.S. Foundation due to overseeing all operations of the foundation.

UTILITY OPERATIONS

LG&E, incorporated in Kentucky in 1913, is a regulated public utility engaged in the generation, transmission, distribution and sale of electric energy and the storage, distribution and sale of natural gas. LG&E is a wholly-owned subsidiary of E.ON U.S. LG&E supplies electricity and natural gas to customers in Louisville and adjacent areas in Kentucky. LG&E's electric service area covers approximately 700 square miles in nine counties in Kentucky, and its natural gas service is provided in the electric service territory and eight additional counties in Kentucky.

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 is a wholly-owned subsidiary of E.ON U.S. KU provides electricity to customers in 77 counties in central, southeastern and western Kentucky, to customers in 5 counties in southwestern Virginia and to fewer than 10 customers in Tennessee.

SERVICE COMPANY

Servco, a Kentucky corporation is a centralized service company registered under PUHCA 2005. It is authorized to conduct business as a service company for E.ON U.S. and its various subsidiaries and affiliates by order of the SEC dated December 6, 2000, commencing operation January 1, 2001. Servco is the service company for affiliated entities, including E.ON U.S., LG&E, KU, Capital Corp, and LEM and provides a variety of administrative, management, engineering, construction, environmental and support services. Servco also coordinates the intercompany billings with E.ON and its affiliates which mainly include transactions for expatriate services. Servco provides its services at cost, as permitted under PUHCA 2005.

Development of the Servco organization was predicated on the fact that if the employee performed activities benefiting more than one affiliate, that employee would become a part of the Servco organization. In many respects, employees residing in typical finance, administrative and general, management and other support departments are fully subject to Servco organizational placement.

Many operational employees dedicated to providing a service to just one affiliate, by definition, are not subject to Servco placement. However management and support staff overseeing the business activities of more than one of these operational groups are subject to Servco placement.

OTHER BUSINESS OPERATIONS

E.ON U.S. Foundation, a charitable foundation exempt from federal income tax under Section 501(c)(3) of the Internal Revenue Code, makes charitable contributions to qualified entities.

Servco also transacts business with E.ON AG and its affiliates on behalf of E.ON U.S.

LEM no longer has major active operations, and continues to have tax and other accounting and certain support activities for its former operations.

Capital Corp. is a holding company for other E.ON U.S. non-utility businesses, which are generally inactive from an operational standpoint, but have certain remaining support or contingent business obligations.

III. TRANSACTIONS WITH AFFILIATES

E.ON U.S. formed Servco, as a service company to provide services for affiliated companies. Servco and affiliated companies (or their parent entities) may enter into service agreements, which may establish the general terms and conditions for providing those services, including those mentioned in Section II of the CAM.

At formation, certain LG&E, KU and E.ON U.S. employees became employees of Servco and such employees continued to provide goods and services to the regulated and non-regulated entities.

Regulated affiliates receive services at cost, pursuant to the service agreements. Non-regulated affiliates generally receive services at cost; however, certain services may permit pricing at fair-market value. The provisions included in contracts or service agreements govern transactions between Servco and the regulated and non-regulated affiliates.

KU and LG&E are required by the KPSC and the VSCC to use the "stand alone" method for allocating their respective tax liabilities (or tax benefits) so that such tax liabilities (or tax benefits) will not exceed the tax liabilities (or tax benefits) each would incur if it filed its tax returns separately from the consolidated returns filed by E.ON US Investments Corp. and its subsidiaries. KU and LG&E have filed a separate E.ON US Investments Corp. and Subsidiaries tax allocation agreement with KPSC and the VSCC. The allocation of the respective tax liabilities (or tax benefits) of LG&E and KU therefore are not within the scope of this CAM.

Definitions of Cost

> ***Tariff Rate*** – The price charged to customers under applicable tariffs on file with federal or state regulatory commissions.
> ***Fair Market Value*** – The price held out by a providing entity to the general public in the normal course of business (i.e. the price at which a reasonable buyer and a reasonable seller are willing to transact in the normal course of business).
> ***Cost*** – The charge used for transactions with affiliates for which no tariff rate or fair market value is applicable. Servco follows the definition of cost defined in PUHCA 2005.

IV. DESCRIPTION OF SERVICES

Service descriptions are organized by Servco responsibility areas, or provider departments, and include the costs associated with providing that service.

Operations Organization

Retail Business Services

Customer Services – providing call center and customer communication services for both electric and gas customers.

Sales and Marketing Services – providing programs for establishing strategies, oversight for marketing, sales and branding of utility and related services, and conducting marketing and sales programs for economic development, and demand side management.

Economic Development and Major Accounts Services – maintaining community development, partnerships with state, regional, and local economic development allies, and customized products and services.

Meter Reading Services – providing meter reading and meter data services.

Meter Operations Services – conducting the testing of meters, completion of all customer-requested service/field credit orders and the installation of commercial/industrial meters.

Meter Asset Management Services – maintaining inventory, quality and environmental issues, policy and standards, technical support, and logistics.

Cash Remittance Services – providing remittance processing, customer payments, and collection services.

Billing Integrity Services – administering and providing customer billings and credit reviews.

Energy Efficiency Services – providing energy efficiency programs to residential and commercial customers to encourage implementation of energy saving measures.

CCS Retail Business Readiness – providing end user support services, development and capture of business metrics and development, and delivery of training for the Company's CCS.

Energy Services

Project Engineering Services – coordinating and managing all major generation construction.

System Laboratory Services – providing system laboratory services to the generating stations.

Generation Services – providing centralized, fleet-wide technical expertise for generation asset management, technical guidance for various functional initiatives and coordination of operational research and development.

Combustion Turbine Operations and Maintenance Services

Fuel Procurement Services – procuring coal, natural gas, oil and other bulk materials for generation facilities and ensuring compliance with price and quality provisions of fuel contracts.

Transmission Strategy and Planning Services

Transmission Protection and Substation Services

Transmission Line Services

Transmission Reliability and Compliance Services

Transmission System Operations Services – providing transmission system control center services.

Transmission EMS Services

Project Development Services – providing project development services to identify and develop potential future sources of energy and capacity to meet the Company's power supply needs.

Energy Marketing Services

Energy Marketing Services – providing market services to take advantage of the highest excess generation prices in the open market.

Market Forecasting Services – providing management services for financial forecasts of the utility market.

Load Forecasting Services – providing short- and long-term load forecasting services.

Generation Planning and Analysis Services – providing short- and long-term generation planning services.

Distribution Operations Services

Network Trouble and Dispatch Services – providing dispatch services, reporting outage situations and coordinating restoration.

Mapping and Records Management Services – providing and maintaining the mapping of the electric infrastructure.

Electric Engineering Services – providing development engineering and construction standards, distribution system planning and analysis, substation construction project management and telecommunications systems design and analyses.

Distribution Asset Management Services – leading management and investment decisions regarding distribution assets, including resource allocation, developing uniform standards and procedures, determining performance targets and managing assets information and data.

Substation Construction and Maintenance Services – providing engineering and design services for substation construction, maintenance and operations areas.

Finance Organization

Finance and Corporate Development Services

Budgeting Services – providing services related to managing, coordinating and reporting for the budgeting process.

Financial Planning Services – providing services related to financial planning and forecasting services, investment analysis and investment planning reports.

Financial Systems – providing business support and electronic data processing services for all financial systems including Oracle Applications, PowerPlant and PowerTax.

Strategic Planning Services – providing services related to benchmarking, analysis of industry events and competitors and medium-term planning and market analysis.

Corporate Controller Organization Services

Internal Financial and Management Reporting Services – providing internal financial reports including standard and ad hoc management reporting.

External Financial Reporting Services – providing financial reports required or used by various external constituencies such as the FERC, the Kentucky Public Service Commission, the Virginia State Corporation Commission, U.S. Department of Energy (DOE), Internal Revenue Service, Municipal Securities Rulemaking Board and financial institutions.

Accounting and Reporting Services – providing U.S. Generally Accepted Accounting Principles (GAAP), FERC, and International Financial Reporting Standards (IFRS) reporting, accounting research and interpretation and promulgation of accounting and internal control procedures. Performing U.S. GAAP and IFRS general ledger account and project analyses, reconciliations and consolidation.

Sundry Billing Services – processing miscellaneous and non-standard billings and maintaining and monitoring associated accounts receivable.

Property Accounting Services – maintaining, analyzing and reporting related to continuing property records.

Energy Marketing Accounting Services – performing month-end validation of all power transactions and resolving any discrepancies; preparing invoices and wires; validating bills from other counterparties; preparing accounting, allocation and analysis of wholesale sales, wholesale purchases, and intercompany sales and purchases; and preparing various FERC, Fuel Adjustment Clause, Southwest Power Pool, and DOE reports.

Revenue Accounting Services – managing and analyzing internal and external revenue reporting.

Corporate Tax and Payroll Organization Services

Payroll Services – providing payroll services including the managing of payroll systems.

Tax Accounting, Compliance and Reporting Services – preparing consolidated and subsidiary federal, state and local income tax returns; current and deferred tax accounting; utility gross receipts tax; sales/use tax; E.ON U.S. Foundation returns and supporting roles for business development and tax legislation.

Tax Planning Services – providing detailed forecasting of foreign, federal and state taxes, as well as, capital-based and property tax planning.

Tax Special Projects Services – providing business or project development, asset dispositions, tax credit studies, review/analysis of proposed tax legislation, etc.

Audit Services – providing independent and objective assurance along with consulting services, internal controls system review and program management.

Corporate Finance and Treasury Services

Cash Management and Investment Services – providing management and monitoring of cash flows including review and acquisition of business entity cash requirements and procurement of short-term financing and credit lines.

Corporate Finance Services – providing overall finance options including evaluating new financing vehicles and instruments, analyzing existing financing positions and raising long-term funds for all entities.

Risk Management Services – managing outside providers of risk services comprised of providing insurance and assisting affiliated entities in managing property and liability risks including claims, security, environmental, safety and consulting services.

Credit Administration Services – providing management of credit risk for wholesale energy sales and major vendors.

Energy Marketing Trading Controls Services – performing daily, weekly, monthly and ad hoc reporting on the trading portfolios related to total exposure, trading limits, and mark-to-market calculations. Other activities include performing an independent valuation and validation of significant transactions, valuation algorithms, ensuring trading system security and testing trading system enhancements.

Energy Marketing Contract Administration Services – negotiating contracts with counterparties, administrating contracts, and maintaining contracts within the trading systems. Additional activities include assisting various departments with contract disputes and preparing and validating confirmations.

Supply Chain and Logistics Services

Procurement and Major Contracts Services – providing for and administering major contract negotiations, requests for quotes, supplier relations and order placement services.

Strategic Sourcing Services – providing strategic sourcing services such as maintaining and analyzing the supplier base and performing supplier selection activities including contract negotiations and ongoing compliance.

Materials Logistics Services – providing order management, materials handling and logistics, and inventory management services.

Sourcing Support Services – providing order management and general field support services for system maintenance, developing and monitoring of key performance metrics, supplying day-to-day variance and reconciliation reporting services, and performing supplier certification services.

Accounts Payable Services – processing payments for purchase orders, check requests, employees' expense reimbursements, etc., and providing ad hoc research and analysis services.

Supplier Diversity – identifying qualified minority and women owned businesses that are able to participate in competitive bidding opportunities, perform on-going work and ultimately become key suppliers to E.ON U.S.

IT Organization

IT Corporate Functions Services – services associated with corporate functions, not specific companies or work groups, and include groups such as IT Finance and Administration, IT Training, and IT Strategy and Planning. This is where corporate standards and programs are developed and administered.

IT Security and Administrative Services – services associated with non-project management, security and administrative support. This includes developing and administering security policies and procedures.

IT Enhancements – providing discretionary, project-based work done in IT. These projects create new client value or add business value to existing products/services.

IT Application Services – services associated with each of the existing applications that IT provides to the business, for example Oracle Applications, PeopleSoft, etc. These services include costs incurred related to application license fees and application support costs.

IT Client Services – services associated with existing end user tools and related productivity software that the users can identify and interact with, such as a personal computer, telephone, email and file and print services.

IT Platform Services – services associated with shared computing platforms, databases, network and IT Service Desk.

General Counsel / Secretary Organization

Compliance, Legal, and Environmental Affairs Services

Legal Services – providing various legal services for all affiliated entities including in-house counsel and staff assistance in the areas of, among others, corporate and securities law, employment law, energy, public utility and regulatory law, contract law, litigation, environmental law and intellectual property law, evaluating legal claims and managing legal fees for outside counsel.

Compliance Services – providing various compliance services for all affiliated entities including compliance assessment and risk management, code of conduct, anti-fraud, ethics and helpline management, etc.

Environmental Affairs Services – providing management services related to performing analyses, monitoring and advocacy of regulatory and legislative environmental matters including securing of permits and approvals, providing environmental technical expertise, and representing the Company in industry groups and before regulatory agencies dealing with environmental issues.

Regulatory Affairs and Government Affairs Management Services

Regulatory Affairs Services – providing management services for compliance with all laws, regulations and other policy requirements, including regulatory filings, expert testimony, tariff administration and compliance, pricing support, and development and monitoring of positions regarding ongoing regulatory matters.

Government Affairs Management Services – maintaining relationships with government policy makers and conducting lobbying activities.

Corporate Communications and Public Affairs Management Services

Internal Communications Services

External and Brand Communications Services – providing all administrative and management support for external communication services, brand image management and corporate events.

Public Affairs Management Services – providing community relations functions, communicating public information to local organizations and providing oversight for communications to employees.

Administration Organization

Operating Services

Facilities and Building Services – providing building and grounds maintenance including coordination of office furniture and equipment purchases/leases, space utilization and layout, and building code and fire protection services.

Security Services – providing security personnel, security and monitoring devices for all affiliated entities.

Production Mail Services – providing production mail services for customer bills and other large customer mailings.

Document Services – providing document printing, reproduction services including mail delivery, scanning, off-site storage and document service desk support.

Right-of-Way Services – obtaining and retaining easements or fee simple property for placement and operation of company and affiliate equipment as well as managing real estate assets and maintaining real estate records.

Transportation Services

Transportation Services – providing and operating transportation fleet for all affiliated companies including developing fleet policy, administering regulatory compliance programs, managing repair and maintenance of vehicles and procuring vehicles.

HR Services

HR Compensation Services – providing services relating to the establishment and oversight of compensation policies for employees.

HR Benefits Services – providing services relating to the establishment and oversight of benefits plans for employees, retirees and survivors. This also includes vendor management, compliance with various laws and regulations, administrative vendor billings, and maintenance of all personnel records.

HR Health and Safety Services – providing services relating to the establishment and oversight of health and safety policies for employees.

HR Organization Development and Training Services – providing initiatives and programs designed to support personal and professional growth, with an emphasis on employee training, individual and career development, performance management, coaching, mentoring, succession planning, employee engagement, and expatriate support.

HR Services – providing services relating to operational and strategic human resources management.

Technical and Safety Training Services – providing training services on technical and safety matters primarily for the Energy Delivery and Energy Services businesses.

Industrial Relations Management Services – providing communication and oversight for union matters, negotiation of union contracts, and union dispute resolution services.

Executive Management Services – providing executive leadership to the corporation which is comprised of the compensation and benefits of the corporate officers and executive assistants.

NATURE AND FREQUENCY OF SERVICES PROVIDED

Ongoing – Provided on a prearranged, continuous basis (i.e., daily)
Frequent – Provided as requested on a regular basis (i.e., several times per month)
Infrequent – Provided as requested on an irregular basis (i.e., several times per year)

All charges by Servco to affiliated entities follow the principle of fully distributed cost. Primary affiliates receiving the service are designated below as:

R – Regulated (LG&E and KU)
NR – Non-regulated (Capital Corp., LEM and E.ON U.S. Foundation)
A – All

SERVICES PROVIDED BY SERVCO TO AFFILIATES

Service	**Frequency**	**Primary Affiliate**
Customer Services	Ongoing	R
Sales and Marketing Services	Frequent	R
Economic Development and Major Accounts Services	Frequent	R
Meter Reading Services	Ongoing	R
Meter Operations Services	Ongoing	R
Meter Asset Management Services	Ongoing	R
Cash Remittance Services	Ongoing	R
Billing Integrity Services	Ongoing	R
Energy Efficiency Department	Ongoing	R
CCS Retail Business Readiness	Ongoing	R
Project Engineering Services	Infrequent	R
System Laboratory Services	Ongoing	R
Generation Services	Ongoing	R
Combustion Turbine Operations and Maintenance Services	Ongoing	R
Fuel Procurement Services	Ongoing	R
Transmission Strategy and Planning Services	Ongoing	R
Transmission Protection and Substation Services	Ongoing	R
Transmission Line Services	Ongoing	R
Transmission Reliability and Compliance Services	Ongoing	R
Transmission System Operations Services	Ongoing	R
Transmission EMS Services	Ongoing	R
Project Development Services	Ongoing	R

Service	Frequency	Primary Affiliate
Energy Marketing Services	Ongoing	R
Market Forecasting Services	Frequent	R
Load Forecasting Services	Frequent	R
Generation Planning and Analysis Services	Ongoing	R
Network Trouble and Dispatch Services	Ongoing	R
Mapping and Records Management Services	Ongoing	R
Electric Engineering Services	Ongoing	R
Distribution Asset Management Services	Ongoing	R
Substation Construction and Maintenance Services	Frequent	R
Budgeting Services	Frequent	A
Financial Planning Services	Frequent	A
Financial Systems	Ongoing	A
Strategic Planning Services	Frequent	A
Internal Financial and Management Reporting Services	Frequent	A
External Financial Reporting Services	Frequent	A
Accounting and Reporting Services	Ongoing	A
Sundry Billings Services	Ongoing	A
Property Accounting Services	Ongoing	A
Energy Marketing Accounting Services	Ongoing	A
Revenue Accounting Services	Ongoing	R
Payroll Services	Ongoing	A
Tax Accounting, Compliance and Reporting Services	Ongoing	A
Tax Planning Services	Infrequent	A
Tax Special Projects Services	Infrequent	A
Audit Services	Ongoing	A
Cash Management and Investment Services	Ongoing	A
Corporate Finance Services	Ongoing	A
Risk Management Services	Ongoing	A
Credit Administration Services	Ongoing	A
Energy Marketing Trading Controls Services	Ongoing	A
Energy Marketing Contract Administration Services	Ongoing	A
Procurement and Major Contracts Services	Ongoing	A
Strategic Sourcing Services	Ongoing	A
Materials Logistics Services	Ongoing	R
Sourcing Support Services	Ongoing	R
Accounts Payable Services	Ongoing	A
Supplier Diversity	Ongoing	A
IT Corporate Functions Services	Ongoing	A
IT Security and Administrative Services	Ongoing	A

Service	Frequency	Primary Affiliate
IT Enhancements	Frequent	A
IT Application Services	Ongoing	A
IT Client Services	Ongoing	A
IT Platform Services	Ongoing	A
Legal Services	Ongoing	A
Compliance Services	Ongoing	A
Environmental Affairs Services	Frequent	R
Regulatory Affairs Services	Ongoing	R
Government Affairs Management Services	Frequent	A
Internal Communications Services	Frequent	A
External and Brand Communications	Frequent	A
Public Affairs Management Services	Frequent	A
Facilities and Building Services	Ongoing	A
Security Services	Ongoing	A
Production Mail Services	Ongoing	R
Document Services	Ongoing	A
Right of Way Services	Ongoing	A
Transportation Services	Ongoing	A
HR Compensation Services	Frequent	A
HR Benefits Services	Frequent	A
HR Health and Safety Services	Frequent	A
HR Organizational Development and Training Services	Frequent	A
HR Services	Frequent	A
Technical and Safety Training Services	Frequent	R
Industrial Relations Management Services	Frequent	R
Executive Management Services	Ongoing	A

V. COST APPORTIONMENT METHODOLOGY

OVERVIEW

The costs of services provided by Servco will be directly assigned, distributed or allocated by activity, project, program, work order or other appropriate basis. The primary basis for charges to affiliates is the direct charge method (see section VI for time reporting procedures). The methodologies listed below pertain to all other costs which are not directly assigned but which make up the fully distributed cost of providing the service.

Directly Assignable – Expenses incurred for activities and services exclusively for the benefit of one affiliate. In many respects, these types of expenses relate to non-Servco employees that perform dedicated services to one affiliate, although Servco employees also directly report where feasible.

Directly Attributable – Expenses incurred for activities and services that benefit more than one affiliate and which can be apportioned using direct measures of costs causation.

Indirectly Attributable – Expenses incurred for activities and services that benefit more than one affiliate and which can be apportioned using general measures of cost causation.

Unattributable – Expenses or portions thereof incurred for activities and services that have been determined as not appropriate for apportionment. The unattributable portions of these costs relate primarily to activities such as corporate diversification, political or philanthropic endeavors and, as such, may be charged, in whole or in part, to Capital Corp.

Servco will allocate the costs of service among the affiliated companies using one of several methods that most accurately distributes the costs. The method of cost allocation varies based on the department rendering the service. Any of the methods may be adjusted for any known and reasonably quantifiable events, or at such time as may be required due to significant changes in the business, but are generally determined annually. The allocation methods used by Servco are as follows:

Contract Ratio – Based on the sum of the physical amount (i.e. tons of coal, cubic feet of natural gas) of the contract for both coal and natural gas for the immediately preceding twelve consecutive calendar months, the numerator of which is for an operating company or an affected affiliate company and the denominator of which is for all operating companies and affected affiliate companies.

Departmental Charge Ratio – A specific Servco department ratio based upon various factors such as labor hours, labor dollars, departmental or entity headcount, etc. The departmental charge ratio typically applies to indirectly attributable costs such as departmental administrative, support, and/or material and supply costs that benefit more than one affiliate and that require allocation using general measures of cost causation. Methods for assignment are department-specific depending on the type of service being performed and are documented and monitored by the Budget Coordinators for each department.

Direct Expense Ratio – Based on the sum of the directly charged expenses at the end of each month for the immediately preceding twelve consecutive calendar months, the numerator of which is for an operating company or affected affiliate company and the denominator of which is for all operating companies and affected affiliate companies.

Electric Peak Load Ratio – Based on the sum of the monthly electric maximum system demands for the immediately preceding twelve consecutive calendar months, the numerator of which is for an operating company and the denominator of which is for all operating companies.

Energy Marketing Ratio – Based on the absolute value of megawatt hours purchased and sold for the immediately preceding twelve consecutive calendar months, the numerator of which is for an operating company or an affiliate and the denominator of which is for all operating companies and affected affiliate companies.

Generation Ratio – Based on the annual forecast of megawatt hours, the numerator of which is for an operating company or an affiliate and the denominator of which is for all operating companies and affected affiliate companies.

Non-Fuel Material and Services Expenditures – Based on non-fuel material and services expenditures, net of reimbursements, for the immediately preceding twelve consecutive calendar months. The numerator is equal to such expenditures for a specific entity and/or line-of-business as appropriate and the denominator is equal to such expenditures for all applicable entities.

Number of Customers Ratio – Based on the number of retail electric and/or gas customers. This ratio will be determined based on the actual number of customers at the end of the previous calendar year. In some cases, the ratio may be calculated based on the type of customer class being served (i.e. Residential, Commercial or Industrial).

Number of Employees Ratio – Based on the number of employees benefiting from the performance of a service. This ratio will be determined based on actual counts of applicable employees at the end of the previous calendar year. A two-step assignment methodology is utilized to properly allocate Servco employee costs to the proper legal entity.

Number of Meters Ratio – Based on the number or types of meters being utilized by all levels of customer classes within the system for the immediately preceding twelve consecutive calendar months. The numerator is equal to the number of meters for each utility and the denominator is equal to the total meters for KU and LG&E.

Number of Transactions Ratio – Based on the sum of transactions occurring in the immediately preceding twelve consecutive calendar months, the numerator of which is for an operating company or an affected affiliate company and the denominator of which is for all operating companies and affected affiliate companies. For example, services pertaining to Materials Logistics would define the transaction as the number of items ordered, picked and disbursed out of the warehouse. Services pertaining to Accounts Payable would define the transaction as the number of invoices processed. The Regulatory Accounting and Reporting Department is responsible for maintaining and monitoring specific service methodology documentation for actual transactions related to Servco billings.

Project Ratio – Based on the total costs for any departmental or affiliate project for the immediately preceding twelve consecutive calendar months, the numerator of which is for an operating company or an affected affiliate company and the denominator of which is for all operating companies and affected affiliate companies.

Retail Revenue Ratio – Based on utility revenues, excluding energy marketing revenues, for the immediately preceding twelve consecutive calendar months, the numerator of which is for an operating company or an affiliate and the denominator of which is for all operating companies and affected affiliate companies.

Revenue Ratio – Based on the sum of the revenue for the immediately preceding twelve consecutive calendar months, the numerator of which is for an operating company or an affected affiliate company and the denominator of which is for all operating companies and affected affiliate companies.

Total Assets Ratio – Based on the total assets at year end for the preceding year, the numerator of which is for an operating company or affected affiliate company and the denominator of which is for all operating companies and affected affiliate companies. In the event of joint ownership of a specific asset, asset ownership percentages are utilized to assign costs.

Transportation Resource Management System Chargeback Rate –Based on the costs associated with providing and operating transportation fleet for all affiliated companies including developing fleet policy, administering regulatory compliance programs, managing repair and maintenance of vehicles and procuring vehicles. Such rates are applied based on the specific equipment employment and the measured usage of services by the various company entities.

Utility Ownership Percentages – Based on the contractual ownership percentages of jointly-owned generating units.

The following service table lists the type of assignments being employed.

Service	**Assignment Method**
Customer Services	Number of Customers Ratio
Sales and Marketing Services	Departmental Charge Ratio
Economic Development and Major Account Services	Number of Customers Ratio
Meter Reading Services	Departmental Charge Ratio
Meter Operations Services	Number of Meters Ratio
Meter Asset Management Services	Number of Meters Ratio
Cash Remittance Services	Revenue Ratio
Billing Integrity Services	Number of Customers Ratio
Energy Efficiency Services	Number of Customers Ratio
CCS Retail Business Readiness	Number of Customers Ratio
Project Engineering Services	Total Assets Ratio
System Laboratory Services	Departmental Charge Ratio
Generation Services	Total Assets Ratio
Combustion Turbine Operations and Maintenance Services	Utility Ownership Percentages
Fuel Procurement Services	Contract Ratio
Transmission Strategy and Planning Services	Departmental Charge Ratio
Transmission Protection and Substation Services	Departmental Charge Ratio
Transmission Line Services	Departmental Charge Ratio
Transmission Reliability and Compliance	Departmental Charge Ratio

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Service	*Assignment Method*
Services	
Transmission System Operations Services	Departmental Charge Ratio
Transmission EMS Services	Departmental Charge Ratio
Project Development Services	Departmental Charge Ratio
Energy Marketing Services	Generation Ratio
Market Forecasting Services	Generation Ratio
Load Forecasting Services	Generation Ratio
Generation Planning and Analysis Services	Electric Peak Load Ratio
Network Trouble and Dispatch Services	Departmental Charge Ratio
Mapping and Records Management Services	Departmental Charge Ratio
Electric Engineering Services	Departmental Charge Ratio
Distribution Asset Management Services	Total Assets Ratio
Substation Construction and Maintenance Services	Departmental Charge Ratio
Budgeting Services	Revenue, Total Assets and Number of Employees Ratios
Financial Planning Services	Direct Expense Ratio
Financial Systems	Number of Employees Ratio
Strategic Planning Services	Departmental Charge Ratio
Internal Financial and Management Reporting Services	Departmental Charge Ratios
External Financial Reporting Services	Departmental Charge Ratios
Accounting and Reporting Services	Departmental Charge Ratios
Sundry Billings Services	Revenue, Total Assets and Number of Employees Ratios
Property Accounting Services	Total Assets Ratio
Energy Marketing Accounting Services	Energy Marketing Ratio
Revenue Accounting Services	Retail Revenue Ratio
Payroll Services	Number of Employees Ratio
Tax Accounting, Compliance and Reporting Services	Direct Expense Ratio
Tax Planning Services	Direct Expense Ratio
Tax Special Projects Services	Direct Charges Only
Audit Services	Project Ratio
Cash Management and Investment Services	Revenue, Total Assets, Number of Employees and Direct Expense Ratios
Corporate Finance Services	Direct Expense Ratio
Risk Management Services	Direct Expense Ratio
Credit Administration Services	Generation Ratio
Energy Marketing Trading Controls Services	Generation Ratio
Energy Marketing Contract Administration Services	Generation Ratio
Procurement and Major Contracts Services	Non-Fuel Material and Services Expenditures Ratio
Strategic Sourcing Services	Non-Fuel Material and Services Expenditures Ratio

Service	***Assignment Method***
Materials Logistics Services	Number of Transactions Ratio
Sourcing Support Services	Non-Fuel Material and Services Expenditures Ratio
Accounts Payable Services	Number of Transactions Ratio
Supplier Diversity	Non-Fuel Material and Services Expenditures Ratio
IT Corporate Functions Services	Number of Employees Ratio
IT Security and Administrative Services	Number of Employees Ratio
IT Enhancements	Number of Employees Ratio
IT Application Services	Number of Employees Ratio
IT Client Services	Number of Employees Ratio
IT Platform Services	Number of Employees Ratio
Legal Services	Departmental Charge Ratio
Compliance Services	Number of Employees Ratio
Environmental Affairs Services	Electric Peak Load Ratio
Regulatory Affairs Services	Revenue Ratio
Government Affairs Management Services	Departmental Charge Ratio
Internal Communication Services	Departmental Charge Ratio
External and Brand Communication Services	Departmental Charge Ratio
Public Affairs Management Services (Corp Responsibility)	Departmental Charge Ratio
Facilities and Building Services	Departmental Charge Ratio
Security Services	Departmental Charge Ratio
Production Mail Services	Number of Customers Ratio
Document Services	Number of Employees Ratio
Right-of-Way Services	Number of Customers Ratio
Transportation Services	Transportation Resource Management System Chargeback Rates
HR Compensation Services	Number of Employees Ratio
HR Benefits Services	Number of Employees Ratio
HR Health and Safety Services	Number of Employees Ratio
HR Organization Development and Training Services	Number of Employees Ratio
HR Services	Number of Employees Ratio
Technical and Safety Training Services	Number of Employees Ratio
Industrial Relations Management Services	Contract Ratio
Executive Management Services	Departmental Charge Ratio

VI. TIME DISTRIBUTION, BILLING AND ASSET TRANSFER POLICIES

OVERVIEW

Servco utilizes ORACLE or other financial systems in which project/task combinations are set up to equate to services. In some cases, departments have set up many projects/tasks that map to services. In many cases, there is a one-to-one relationship between the project/task and the service. The ORACLE system also automatically captures the home company (providing the service) and the charge company (receiving the service). Regardless of the method of reporting, charges related to specific services reside on the company receiving the service and therefore can be identified for billing purposes as well as for preparation of Servco financial statements. This ensures that:

1. Separation of costs between regulated and non-regulated affiliates will be maintained
2. Intercompany transactions and related billings are structured so that non-regulated activities are not subsidized by regulated affiliates
3. Adequate audit trails exist on the books and records

BILLING POLICIES

Billings for transactions between Servco and affiliates are issued on a timely basis with documentation sufficient to provide the receiving party with enough detail to understand the nature of the billing, the relevant components, and other information as required by affiliates. Financial settlements for transactions are made within 30 days. Interest charges, which are based on market rates for similar tenors of similarly rated entities as of the date of the loan, may apply.

ASSET TRANSFERS

Unless otherwise permitted by regulatory authority or exception, (i) transfers or sales of assets from regulated affiliates to non-regulated affiliates will be priced at the greater of cost or fair market value; (ii) transfers or sales of assets from non-regulated affiliates to regulated affiliates will be priced at the lower of cost or fair market value and (iii) transfers of assets between regulated affiliates shall be priced at no more than cost less depreciation. Settlement of liabilities will be treated in the same manner.

TIME DISTRIBUTION

Servco has three methods of distribution to record employee salaries and wages while providing services for the affiliated entities: Positive time reporting, allocation time reporting and exception time reporting. Each department's job activities will dictate the time reporting method used.

Positive Time Reporting

Positive time reporting or direct time reporting requires all employees in a department to track all chargeable hours every day. Time may be charged to the nearest quarter hour.

Departments that have positive time reporting have labor-based activities that are easily trackable given the project/task code combinations noted above. All employees are given appropriate project numbers that are associated with the service that is being provided. The proper coding for direct assignment of costs is on various source documents, including the Virtual Online Time System (VOLTS) and disbursement requests. Each department or project manager is responsible for ensuring employees charge the appropriate charge codes for the services performed. This form of time reporting is documented in the VOLTS, which upon completion, is approved by the employees' immediate supervisor.

Allocation Time Reporting

Allocation time reporting allows for certain departments to set up a predefined allocation percentage to affiliated company project/tasks. This is typically the case when the department is transaction-based, therefore, performing routine, similar tasks benefiting multiple affiliates. Each department will use its ratio (see ratio assignment listing in section V) that was assigned by its Budget Coordinator to allocate the appropriate time to individual charge numbers that are associated to that department's services. Unless otherwise permitted by regulatory authority or exception, the selection of ratios and the calculation of allocation percentages should be derived from or bear relationship to an empirical analysis of a prior representative period. These allocation percentages are reviewed on an annual basis to update to actual allocation percentages when needed.

Exception Time Reporting

If an employee was working on a completely new project that had not been defined within the monthly or annual allocation process, then the employee would be given the new allocation with project/task code, update his/her time allocation accordingly and get his/her manager's approval. If an allocation from a previous pay period needs to be adjusted then that correction can be entered into the VOLTS by using the "in and out" function.

Exhibit No. VASCC-2L

KENTUCKY UTILITIES COMPANY

ANNUAL REPORT OF AFFILIATE TRANSACTIONS WITH
LG&E AND KU SERVICES COMPANY (E.ON IS GMBH)
January 1, 2010 - December 31, 2010

No. 11 Kentucky Utilities Company, d/b/a/ Old Dominion Power Company, shall file an Annual Report of Affiliate Transactions indirectly undertaken for the benefit of non-regulated affiliates with the Director of Public Utility Accounting of the Commission by no later than May 1 of each year, for the preceding calendar year, beginning May 1, 1999.
Such report should include the following information:
1) non-regulated affiliate's name;
2) description of each type of service provided;
3) dates that each type of service was provided;
4) total dollar value (cost for each type of service provided);
5) component costs of each type of service provided (i.e., direct/indirect labor, fringe benefits, travel/housing, materials, supplies, indirect miscellaneous expenses, equipment/facilities charges, and overheads);
6) profit component of each type of service and how profit component is determined; and
7) comparable market values and supporting documentation for each type of service provided.

RESPONSES:

1) LG&E and KU Services Company (E.ON IS GmbH)

2) IT Organization Services

3) IT Organization Services — March, July 2010

4) $ 4,684.23

5) Component costs are:

Software Implementation	$	4,684.23
	$	4,684.23

6) LG&E and KU Services Company's cost allocation policies are to use at-cost pricing for affiliate transactions, without any profit component.

7) Transfers or sales of assets, goods or services between KU and LG&E and KU Services Company are priced at cost, which approximates market value.

Exhibit No. VASCC-2M

KENTUCKY UTILITIES COMPANY

ANNUAL REPORT OF AFFILIATE TRANSACTIONS WITH
LG&E AND KU SERVICES COMPANY (E.ON UK)
January 1, 2010 - December 31, 2010

No. 11 Kentucky Utilities Company, d/b/a/ Old Dominion Power Company, shall file an Annual Report of Affiliate Transactions indirectly undertaken for the benefit of non-regulated affiliates with the Director of Public Utility Accounting of the Commission by no later than May 1 of each year, for the preceding calendar year, beginning May 1, 1999. Such report should include the following information:
1) non-regulated affiliate's name;
2) description of each type of service provided;
3) dates that each type of service was provided;
4) total dollar value (cost for each type of service provided);
5) component costs of each type of service provided (i.e., direct/indirect labor, fringe benefits, travel/housing, materials, supplies, indirect miscellaneous expenses, equipment/facilities charges, and overheads);
6) profit component of each type of service and how profit component is determined; and
7) comparable market values and supporting documentation for each type of service provided.

RESPONSES:

1) LG&E and KU Services Company (E.ON UK)

2) Retail Business Services

3) Retail Business Services — January, February, March, June 2010

4) $ 7,463.67

5) Component costs are:

Direct - Indirect Labor	$ 7,463.67
	$ 7,463.67

6) LG&E and KU Services Company's cost allocation policies are to use at-cost pricing for affiliate transactions, without any profit component

7) Transfers or sales of assets, goods or services between KU and LG&E and KU Services Company are priced at cost, which approximates market value.

KENTUCKY UTILITIES COMPANY
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FOR THE PERIOD JANUARY 1, 2010 - DECEMBER 31, 2010

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Kentucky Utilities Company
Affiliate Services
2010 Intercompany Cost Attribution Matrix
KU Provider of Services

Operations Organization	Jan-2010	Feb-2010	Mar-2010	Apr-2010	May-2010	Jun-2010	Jul-2010	Aug-2010	Sep-2010	Oct-2010	Nov-2010	Dec-2010	Total
Audit Services	-	-	-		587.32	-	-		-	-	-	-	587.32
Compliance, Legal, and Environmental Affairs Services	(855.76)	-	-	-	-	-		-	90,755.84	272.90	233,240.64	-	323,413.62
Controller Organization Services	-	-	-	-	-	1,384.60	-	-	119.47	-	-	-	1,504.07
Corporate Finance and Treasury Services	2,593.77	-	1,694,757.49	87.45	216.38	117.51	193.05	-	-	147.64	-	-	1,698,113.29
Corporate Tax and Payroll Organization Services	-	-	-	1,862,603.00	-	-	11,178,138.00	-	5,938,435.00	1,424,650.00	-	12,000,254.71	32,404,080.71
Distribution Operations Services	1,206.60	3,285.47	442,092.48	2,378.60	2,828.05	520,761.58	7,919.50	38,348.46	10,286.28	2,721.61	14,720.00	6,276.84	1,052,825.47
Distributions Operations Services	495.15	-	395,559.15	-	-	220,596.34	81.04	31,510.51	-	-	1,464.34	2,291.65	651,999.08
Energy Marketing Services	1,516,286.94	4,444,782.89	1,147,501.52	676,541.28	1,252,295.47	456,255.02	667,163.82	559,446.54	633,993.57	1,147,564.34	1,315,643.03	1,147,803.20	15,265,277.62
Energy Services	28,729,801.08	43,695,056.27	45,746,809.90	45,029,171.19	39,489,521.33	67,756,285.31	26,145,025.31	52,462,914.56	43,034,422.18	40,242,357.76	26,141,245.67	39,896,360.76	498,368,971.30
Executive Management Services	353.50	354.46	36,040.82	356.34	357.30	355.35	359.23	360.21	370.09	1,064.43	108,986.44	831.17	149,789.34
Finance and Corporate Development Services	-	-	-	-	-	-	-	41,284.00	13,281.00	7,656.00	70,100.04	-	132,321.04
HR Services	29,600.67	3,632.49	137,791.61	595,491.08	(43,161.25)	(15,308.05)	19,353.31	20,791.54	17,447.51	32,331.99	10,712.55	54,122.19	862,805.64
IT Organization	2,385.03	45,216.59	1,685.89	3,111.83	670.36	8,680.69	1,228.67	872.26	1,101.70	1,095.14	1,049.18	797.18	67,895.52
Operating Services	-	213.50	18,059.51	-	-	5,649.37	-	2,091.30	-	-	-	467.00	26,480.68
Regulatory Affairs and Government Affairs Management Services	430.46	251.33	9,698.95	269.62	220.34	25,717.45	320.33	568.27	282.08	287.24	(217.34)	888.83	38,717.56
Retail Business Services	8,780.24	1,520.89	222,075.95	2,665.35	2,478.69	24,354.66	5,134.00	9,377.82	6,586.10	8,466.85	7,833.03	18,486.22	317,759.80
Supply Chain and Logistics Services	172,479.44	114,622.15	(15,395.45)	65,842.24	67,679.97	45,946.98	67,551.86	44,522.39	75,803.66	326,039.32	235,831.82	144,874.66	1,345,999.04
Transportation Services	-	-	135,154.48	70.88	-	(39.60)	-	-	10,425.80	8,353.13	7,562.96	123.32	161,650.97
Total	30,763,557.10	48,308,936.04	49,971,832.30	48,238,588.86	40,773,893.96	69,050,757.21	38,092,469.02	53,212,087.86	49,833,310.28	43,203,009.35	28,148,172.36	53,273,577.73	552,870,192.07

Refer to the LG&E and KU Services Cost Allocation Manual for a description of services, the nature and frequency of services provided, cost apportionment methodology, and allocation methods.

Exhibit No. VASCC-1A

KENTUCKY UTILITIES COMPANY

ANNUAL REPORT OF AFFILIATE TRANSACTIONS WITH
LOUISVILLE GAS AND ELECTRIC COMPANY
January 1, 2010 - December 31, 2010

No. 10 Kentucky Utilities Company, d/b/a/ Old Dominion Power Company, shall file an Annual Report of Affiliate Transactions undertaken with Louisville Gas and Electric Company and LG&E and KU Services Company with the Director of Public Utility Accounting of the Commission by no later than May 1 of each year, for the preceding calendar year, beginning May 1, 1999. Such report should include the following information:

1) affiliate's name;
2) description of each affiliate arrangement/agreement;
3) dates of each affiliate arrangement/agreement;
4) total dollar amount of each affiliate arrangement/agreement;
5) component costs of each arrangement/agreement where services are provided to an affiliate (i.e., direct/indirect labor, fringe benefits, travel/housing, materials, supplies, indirect miscellaneous expenses, equipment/facilities charges, and overheads);
6) profit component of each arrangement/agreement where services are provided to an affiliate and how such component is determined;
7) comparable market values and documentation related to each arrangement/agreement;
8) percent/dollar amount of each affiliate arrangement/agreement charged to expense and/or capital accounts;
9) allocation bases/factors for allocated costs;
10) list and description of each utility asset transfer over $250,000; and
11) list by functional group of utility assets transfers valued less than $250,000.

RESPONSES:

1) Louisville Gas and Electric Company

2) Services Agreement Case Nos. PUA970048, PUA000050

3) May 4 1998 & January 1, 2001

4) $ 68,177,623.54

5) Component costs are:

Direct - Indirect Labor	$	748,134.99
Fringe Benefits/Overheads	$	138,438.53
Equipment/Facilities	$	442,834.16
Materials/Fuels	$	618,461.98
Outside Services	$	1,964,989.65
Indirect Miscellaneous Expenses (Vouchers)	$	27,060,530.93
Capital Expenditures	$	23,428,899.79
Power Sales/Purchases	$	13,775,333.51
	$	68,177,623.54

6) LG&E and KU's cost allocation policies are to use at-cost pricing for affiliate transactions, without any profit component.

7) Transfers or sales of assets, goods or services between KU and LG&E are priced at cost, which approximates market value.

8) All costs charged to LG&E are charged to Intercompany accounts. The breakdown of services provided by KU for LG&E consists of 34.36% Capital expense with a cost of $23,428,899.79 and 65.64% O&M expense with a cost of $44,748,723.75

9) Allocation percentages for overhead calculations on labor as applicable in 2010 are as follows:

Part-Time Labor	108.89%
Temporary Labor	19.04%
Full-Time Labor	108.89%

Allocation percentages for overhead calculations on material issued from inventory in 2010 are as follows:

Stores, Freight & Handling - T & D	23.00%
Stores, Freight & Handling - Production	23.00%

Allocation percentages on labor and non-labor for capital projects in 2010 are as follows:

Construction Overheads - Distribution	14.00%
Construction Overheads - Production	2.32%
Construction Overheads - Transmission	15.00%
Administrative and General	2.40%

Allocation percentages for overhead calculations on all labor from departments to which a vehicle is assigned for 2010 are as follows:

TRMS	13.30%

10) There were no asset transfers over $250,000.

11) Transfer of construction equipment from KU to LG&E for $93,248.00.

Exhibit No VASCC-1B

KENTUCKY UTILITIES COMPANY

ANNUAL REPORT OF AFFILIATE TRANSACTIONS WITH
LG&E AND KU SERVICES COMPANY
January 1, 2010 - December 31, 2010

No. 10 Kentucky Utilities Company, d/b/a/ Old Dominion Power Company, shall file an Annual Report of Affiliate Transactions undertaken with Louisville Gas and Electric Company and LG&E and KU Services Company with the Director of Public Utility Accounting of the Commission by no later than May 1 of each year, for the preceding calendar year, beginning May 1, 1999. Such report should include the following information:
1) affiliate's name;
2) description of each affiliate arrangement/agreement;
3) dates of each affiliate arrangement/agreement;
4) total dollar amount of each affiliate arrangement/agreement;
5) component costs of each arrangement/agreement where services are provided to an affiliate (i.e., direct/indirect labor, fringe benefits, travel/housing, materials, supplies, indirect miscellaneous expenses, equipment/facilities charges, and overheads);
6) profit component of each arrangement/agreement where services are provided to an affiliate and how such component is determined;
7) comparable market values and documentation related to each arrangement/agreement;
8) percent/dollar amount of each affiliate arrangement/agreement charged to expense and/or capital accounts;
9) allocation bases/factors for allocated costs;
10) list and description of each utility asset transfer over $250,000; and
11) list by functional group of utility assets transfers valued less than $250,000.

RESPONSES:

1) LG&E and KU Services Company

2) Services Agreement Case No. PUA000050

3) January 1, 2001

4) $ 451,889,064.83

5) Component costs are:

Direct - Indirect Labor	$	256,773.29
Fringe Benefits/Overheads	$	33,954.26
Equipment/Facilities	$	22,496.75
Materials/Fuels	$	449,225,530.69
Outside Services	$	20,747.51
Indirect Miscellaneous Expenses (Vouchers)	$	2,306,037.32
Capital Expenditures	$	23,525.01
	$	451,889,064.83

6) LG&E and KU Services Company's cost allocation policies are to use at-cost pricing for affiliate transactions, without any profit component.

7) Transfers or sales of assets, goods or services between KU and LG&E and KU Services Company are priced at cost, which approximates market value.

8) All costs charged to LG&E and KU Services Company are charged to Intercompany accounts. The breakdown of services provided by KU for LG&E and KU Services Company consists of .005% Capital expense with a cost of $23,525.01 and 99.995% O&M expense with a cost of $451,865,539.82.

9) Allocation percentages for overhead calculations on labor as applicable in 2010 are as follows:

Part-Time Labor	108.89%
Temporary Labor	19.04%
Full-Time Labor	108.89%

Allocation percentages for overhead calculations on material issued from inventory in 2010 are as follows:

Stores, Freight & Handling - T & D	23.00%
Stores, Freight & Handling - Production	23.00%

Allocation percentages on labor and non-labor for capital projects in 2010 are as follows:

Construction Overheads - Distribution	14.00%
Construction Overheads - Production	2.32%
Construction Overheads - Transmission	15.00%
Administrative and General	2.40%

Allocation percentages for overhead calculations on all labor from departments to which a vehicle is assigned for 2010 are as follows:

TRMS	13.30%

10) There were no utility asset transfers over $250,000.

11) There were no utility asset transfers less than $250,000.

Exhibit No. VASCC-1C

KENTUCKY UTILITIES COMPANY

ANNUAL REPORT OF AFFILIATE TRANSACTIONS WITH
LG&E AND KU SERVICES COMPANY (WESTERN KENTUCKY ENERGY CORP.)
January 1, 2010 - December 31, 2010

No 11 Kentucky Utilities Company, d/b/a/ Old Dominion Power Company, shall file an Annual Report of Affiliate Transactions indirectly undertaken for the benefit of non-regulated affiliates with the Director of Public Utility Accounting of the Commission by no later than May 1 of each year, for the preceding calendar year, beginning May 1, 1999.
Such report should include the following information:
1) non-regulated affiliate's name;
2) description of each type of service provided;
3) dates that each type of service was provided;
4) total dollar value (cost for each type of service provided);
5) component costs of each type of service provided (i e., direct/indirect labor, fringe benefits, travel/housing, materials, supplies, indirect miscellaneous expenses, equipment/facilities charges, and overheads);
6) profit component of each type of service and how profit component is determined; and
7) comparable market values and supporting documentation for each type of service provided.

RESPONSES:

1) LG&E and KU Services Company (Western Kentucky Energy Corp.)

2) Distribution Operations Services
Energy Services
HR Services
IT Organization Services

3)

Distribution Operations Services	July 2010
Energy Services	January - November 2010
HR Services	August 2010
IT Organization Services	April 2010

4)

Distribution Operations Services	$	255 60
Energy Services	$	30,516 77
HR Services	$	146 27
IT Organization Services	$	1,763.58
	$	32,682.22

5) Component costs are:

Direct - Indirect Labor	$	4,481.69
Fringe Benefits/Overheads	$	-
Equipment/Facilities	$	26,290.68
Materials/Fuels	$	-
Outside Services	$	146.27
Indirect Miscellaneous Expenses (Vouchers)	$	1,763.58
Capital Expenditures	$	-
	$	32,682.22

6) LG&E and KU Services Company's cost allocation policies are to use at-cost pricing for affiliate transactions, without any profit component.

7) Transfers or sales of assets, goods or services between KU and LG&E and KU Services Company are priced at cost, which approximates market value

Exhibit No. VASCC-1D

KENTUCKY UTILITIES COMPANY

ANNUAL REPORT OF AFFILIATE TRANSACTIONS WITH
LG&E AND KU SERVICES COMPANY (LG&E AND KU CAPITAL LLC)
January 1, 2010 - December 31, 2010

No 11 Kentucky Utilities Company, d/b/a/ Old Dominion Power Company, shall file an Annual Report of Affiliate Transactions indirectly undertaken for the benefit of non-regulated affiliates with the Director of Public Utility Accounting of the Commission by no later than May 1 of each year, for the preceding calendar year, beginning May 1, 1999
Such report should include the following information:
1) non-regulated affiliate's name;
2) description of each type of service provided;
3) dates that each type of service was provided;
4) total dollar value (cost for each type of service provided);
5) component costs of each type of service provided (i.e., direct/indirect labor, fringe benefits, travel/housing, materials, supplies, indirect miscellaneous expenses, equipment/facilities charges, and overheads);
6) profit component of each type of service and how profit component is determined; and
7) comparable market values and supporting documentation for each type of service provided

RESPONSES:

1) LG&E and KU Services Company (LG&E and KU Capital LLC)

2) Audit Services
Compliance, Legal, and Environmental Affairs Services
Distribution Operations Services
Energy Services
Executive Management Services
HR Services
IT Organization Services
Operating Services
Retail Business Services
Transportation Services

3)

Audit Services	May 2010
Compliance, Legal, and Environmental Affairs Services	January, September 2010
Distribution Operations Services	March, April, July, October 2010
Energy Services	January - December 2010
Executive Management Services	January - December 2010
HR Services	January - December 2010
IT Organization Services	January - December 2010
Operating Services	February 2010
Retail Business Services	April 2010
Transportation Services	October - December 2010

4)

Audit Services	$	23.04
Compliance, Legal, and Environmental Affairs Services	$	90,720.69
Distribution Operations Services	$	521.36
Energy Services	$	121,666.02
Executive Management Services	$	4,770.79
HR Services	$	31,053.86
IT Organization Services	$	1,361.06
Operating Services	$	21.35
Retail Business Services	$	15.96
Transportation Services	$	8,938.83
	$	259,092.96

5) Component costs are:

Direct - Indirect Labor	$	45,450.69
Fringe Benefits/Overheads	$	15,674.80
Equipment/Facilities	$	3,804.13
Materials/Fuels	$	1,351.28
Outside Services	$	121,885.95
Indirect Miscellaneous Expenses (Vouchers)	$	69,610.73
Capital Expenditures	$	1,315.38
	$	259,092.96

6) LG&E and KU Services Company's cost allocation policies are to use at-cost pricing for affiliate transactions, without any profit component

7) Transfers or sales of assets, goods or services between KU and LG&E and KU Services Company are priced at cost which approximates market value

Exhibit No. VASCC-1E

KENTUCKY UTILITIES COMPANY

ANNUAL REPORT OF AFFILIATE TRANSACTIONS WITH
LG&E AND KU SERVICES COMPANY (LG&E AND KU ENERGY LLC)
January 1, 2010 - December 31, 2010

No. 11 Kentucky Utilities Company, d/b/a/ Old Dominion Power Company, shall file an Annual Report of Affiliate Transactions indirectly undertaken for the benefit of non-regulated affiliates with the Director of Public Utility Accounting of the Commission by no later than May 1 of each year, for the preceding calendar year, beginning May 1, 1999.
Such report should include the following information:
1) non-regulated affiliate's name;
2) description of each type of service provided;
3) dates that each type of service was provided;
4) total dollar value (cost for each type of service provided);
5) component costs of each type of service provided (i.e., direct/indirect labor, fringe benefits, travel/housing, materials, supplies, indirect miscellaneous expenses, equipment/facilities charges, and overheads);
6) profit component of each type of service and how profit component is determined; and
7) comparable market values and supporting documentation for each type of service provided.

RESPONSES:

1) LG&E and KU Services Company (LG&E and KU Energy LLC)

2) Corporate Tax and Payroll Organization Services

3) Corporate Tax and Payroll Organization Services — April, July, September, October, December 2010

4) $ 32,397,623.00

5) Component costs are:

Direct - Indirect Labor	$	-
Fringe Benefits/Overheads	$	-
Equipment/Facilities	$	-
Materials/Fuels	$	-
Outside Services	$	-
Indirect Miscellaneous Expenses (Vouchers)	$	-
Tax Settlements	$	32,397,623.00
Capital Expenditures	$	-
	$	32,397,623.00

6) LG&E and KU Services Company's cost allocation policies are to use at-cost pricing for affiliate transactions, without any profit component.

7) Transfers or sales of assets, goods or services between KU and LG&E and KU Services Company are priced at cost, which approximates market value.

Exhibit No. VASCC-1F

KENTUCKY UTILITIES COMPANY

ANNUAL REPORT OF AFFILIATE TRANSACTIONS WITH
LG&E AND KU SERVICES COMPANY (E.ON Kraftwerke)
January 1, 2010 - December 31, 2010

No. 11 Kentucky Utilities Company, d/b/a/ Old Dominion Power Company, shall file an Annual Report of Affiliate Transactions indirectly undertaken for the benefit of non-regulated affiliates with the Director of Public Utility Accounting of the Commission by no later than May 1 of each year, for the preceding calendar year, beginning May 1, 1999. Such report should include the following information:

1) non-regulated affiliate's name;
2) description of each type of service provided;
3) dates that each type of service was provided;
4) total dollar value (cost for each type of service provided);
5) component costs of each type of service provided (i.e., direct/indirect labor, fringe benefits, travel/housing, materials, supplies, indirect miscellaneous expenses, equipment/facilities charges, and overheads);
6) profit component of each type of service and how profit component is determined; and
7) comparable market values and supporting documentation for each type of service provided.

RESPONSES:

1) LG&E and KU Services Company (E.ON Kraftwerke)

2) Energy Services

3) Energy Services — January - May, October 2010

4) $ 114,105.52

5) Component costs are:

Direct - Indirect Labor	$	107,581.34
Moving Expenses	$	6,524.18
	$	114,105.52

6) LG&E and KU Services Company's cost allocation policies are to use at-cost pricing for affiliate transactions, without any profit component.

7) Transfers or sales of assets, goods or services between KU and LG&E and KU Services Company are priced at cost, which approximates market value.

Kentucky Utilities Company
Affiliate Services
2010 Intercompany Cost Attribution Matrix
KU Recipient of Services

Operations Organization	Jan-2010	Feb-2010	Mar-2010	Apr-2010	May-2010	Jun-2010	Jul-2010	Aug-2010	Sep-2010	Oct-2010	Nov-2010	Dec-2010	Total
Audit Services	77,762.85	74,174.43	80,053.43	77,311.38	80,995.02	86,155.83	86,204.99	74,956.79	73,671.91	72,385.92	72,183.73	98,592.64	953,648.92
Compliance, Legal, and Environmental Affairs Services	940,101.71	505,791.52	990,565.94	644,376.79	776,611.89	1,446,079.32	415,241.83	475,664.06	632,931.34	562,957.77	684,855.24	1,353,850.84	9,429,028.25
Controller Organization Services	262,149.67	268,546.69	347,175.31	305,058.72	300,879.96	298,650.41	290,632.88	303,492.04	320,624.78	368,554.03	288,166.44	457,157.30	3,611,098.23
Corporate Communications and Public Affairs Management Services	117,164.41	224,140.32	240,162.59	191,638.72	214,453.23	240,576.22	217,906.69	208,344.24	171,235.36	275,555.92	162,079.69	302,162.02	2,565,426.21
Corporate Finance and Treasury Services	1,425,247.39	193,785.43	5,570,059.66	166,054.94	157,800.43	377,952.57	126,587.92	178,335.52	451,512.36	134,527.17	7,915,736.20	1,164,463.41	17,662,064.00
Corporate Tax and Payroll Organization Services	69,436.17	65,722.53	5,836,376.49	13,285,209.28	144,048.80	18,169,519.38	(29,855.62)	84,131.70	24,777,665.24	32,779,106.61	84,468.96	121,629.10	95,387,459.64
Distribution Operations Services	548,965.01	269,519.19	269,230.44	910,477.37	243,691.56	229,492.02	237,641.28	462,840.47	513,043.45	2,741,992.22	1,330,515.64	1,164,084.45	8,920,493.10
Distributions Operations Services	183,724.44	199,325.21	209,177.96	181,957.78	180,834.96	190,644.04	182,861.09	192,595.42	268,758.65	226,276.24	179,969.76	241,153.53	2,437,279.08
Energy Marketing Services	8,810,083.28	9,927,386.19	6,794,959.49	10,176,882.02	8,148,586.35	5,613,782.14	7,128,848.02	6,978,660.60	8,729,922.46	10,672,173.10	10,003,966.32	11,761,287.22	104,746,537.19
Energy Services	39,921,389.61	45,667,001.20	59,762,835.43	48,032,358.93	47,856,169.23	84,192,355.58	43,567,421.36	70,973,520.76	57,177,224.61	52,574,644.58	32,078,648.72	57,777,456.86	639,591,027.09
Executive Management Services	119,619.15	245,794.12	317,552.36	284,602.23	317,429.50	304,153.30	268,963.15	328,101.29	279,602.03	430,815.40	461,124.11	668,210.35	4,025,965.99
Finance and Corporate Development Services	206,887.07	213,956.68	233,486.80	202,617.72	267,346.36	189,105.14	276,915.20	276,862.26	210,765.36	140,030.53	209,042.80	84,359.07	2,511,414.99
HR Services	2,890,872.13	1,839,144.12	2,090,147.16	1,408,515.95	1,567,156.67	1,921,261.90	2,985,669.42	1,433,095.09	1,760,171.72	809,825.99	(329,979.78)	1,135,199.19	19,511,079.56
IT Organization	2,017,341.03	2,319,093.19	2,294,396.16	2,904,389.66	2,929,144.85	3,049,443.49	2,887,685.12	2,991,362.75	3,508,802.78	5,473,904.83	6,464,181.98	6,205,854.83	43,045,580.67
Operating Services	816,587.25	452,655.73	1,167,430.59	710,405.18	1,227,955.64	1,218,535.05	919,439.88	692,897.01	1,029,363.32	1,236,791.19	906,937.20	1,351,878.52	11,730,876.56
Regulatory Affairs and Government Affairs Management Services	175,274.43	202,929.71	1,699,637.99	186,954.89	172,679.98	208,344.86	160,784.40	162,123.79	172,694.28	161,253.52	153,001.43	207,953.53	3,663,632.91
Retail Business Services	1,337,402.66	1,881,506.97	2,602,678.76	1,650,662.40	1,867,742.75	1,808,893.90	2,048,851.40	2,114,427.22	2,276,851.57	2,896,178.78	2,211,036.58	2,093,628.46	24,789,931.45
Supply Chain and Logistics Services	195,667.89	293,955.11	342,175.31	220,298.63	271,825.40	307,187.69	285,082.37	235,692.59	266,621.17	90,974.88	204,921.80	402,797.37	3,117,200.21
Transportation Services	26,210.16	29,258.37	35,091.66	37,420.25	35,344.98	32,940.70	18,529.52	25,483.06	30,316.22	29,195.75	26,977.51	38,136.99	354,906.17
Total	60,141,885.31	64,872,733.71	90,892,193.53	81,577,182.84	66,770,697.56	119,885,083.54	62,075,390.92	88,192,586.66	102,651,989.61	111,677,145.43	63,107,894.53	86,629,856.38	998,474,651.22

Refer to the LG&E and KU Services Cost Allocation Manual for a description of services, the nature and frequency of services provided, cost apportionment methodology, and allocation methods.

Exhibit No. VASCC-2A

KENTUCKY UTILITIES COMPANY

ANNUAL REPORT OF AFFILIATE TRANSACTIONS WITH
LOUISVILLE GAS AND ELECTRIC COMPANY
January 1, 2010 - December 31, 2010

No. 10 Kentucky Utilities Company, d/b/a/ Old Dominion Power Company, shall file an Annual Report of Affiliate Transactions undertaken with Louisville Gas and Electric Company and LG&E and KU Services Company with the Director of Public Utility Accounting of the Commission by no later than May 1 of each year, for the preceding calendar year, beginning May 1, 1999. Such report should include the following information:

1) affiliate's name;
2) description of each affiliate arrangement/agreement;
3) dates of each affiliate arrangement/agreement;
4) total dollar amount of each affiliate arrangement/agreement;
5) component costs of each arrangement/agreement where services are provided to an affiliate (i.e., direct/indirect labor, fringe benefits, travel/housing, materials, supplies, indirect miscellaneous expenses, equipment/facilities charges, and overheads);
6) profit component of each arrangement/agreement where services are provided to an affiliate and how such component is determined;
7) comparable market values and documentation related to each arrangement/agreement;
8) percent/dollar amount of each affiliate arrangement/agreement charged to expense and/or capital accounts;
9) allocation bases/factors for allocated costs;
10) list and description of each utility asset transfer over $250,000; and
11) list by functional group of utility assets transfers valued less than $250,000

RESPONSES:

1) Louisville Gas and Electric Company

2) Services Agreement Case Nos. PUA970048, PUA000050

3) May 4, 1998 & January 1, 2001

4) $257,591,177.87

5) Component costs are:

Direct - Indirect Labor	$	935,158.33
Fringe Benefits/Overheads	$	(450,468.97)
Equipment/Facilities	$	2,451,176.89
Materials/Fuels	$	53,983,412.83
Outside Services	$	2,539,979.06
Indirect Miscellaneous Expenses (Vouchers)	$	65,214,280.10
Capital Expenditures	$	33,641,867.33
Power Sales/Purchases	$	99,275,772.30
	$	257,591,177.87

6) LG&E and KU's cost allocation policies are to use at-cost pricing for affiliate transactions, without any profit component

7) Transfers or sales of assets, goods or services between KU and LG&E are priced at cost, which approximates market value.

8) All costs received from LG&E are charged to the appropriate expense or capital account depending on the service performed for KU. Total Capital expense was 13.06% with a cost of $33,641,867.33 and total O&M expense was 86.94% with a cost of $223,949,310.54

9) Allocation percentages for overhead calculations on labor as applicable in 2010 are as follows:

Part-Time Labor	109.28%
Temporary Labor	19.33%
Full-Time Labor	109.28%

Allocation percentages for overhead calculations on material issued from inventory in 2010 are as follows:

Stores, Freight & Handling - T & D	14.50%
Stores, Freight & Handling - Production	14.50%

Allocation percentages on labor and non-labor for capital projects in 2010 are as follows:

Construction Overheads - Distribution	12.00%
Construction Overheads - Production	0.65%
Construction Overheads - Transmission	15.00%
Administrative and General	1.70%

Allocation percentages for overhead calculations on all labor from departments to which a vehicle is assigned for 2010 are as follows:

TRMS	6.60%

10) There were no asset transfers over $250,000

11) Transfer of transformer from LG&E to KU for $2,250.
Transfer of circuit breaker from LG&E to KU for $71,305.28.

Exhibit No. VASCC-2B

KENTUCKY UTILITIES COMPANY

ANNUAL REPORT OF AFFILIATE TRANSACTIONS WITH
LG&E AND KU SERVICES COMPANY
January 1, 2010 - December 31, 2010

No. 10 Kentucky Utilities Company, d/b/a/ Old Dominion Power Company, shall file an Annual Report of Affiliate Transactions undertaken with Louisville Gas and Electric Company and LG&E and KU Services Company with the Director of Public Utility Accounting of the Commission by no later than May 1 of each year, for the preceding calendar year, beginning May 1, 1999.
Such report should include the following information:
1) affiliate's name;
2) description of each affiliate arrangement/agreement;
3) dates of each affiliate arrangement/agreement;
4) total dollar amount of each affiliate arrangement/agreement;
5) component costs of each arrangement/agreement where services are provided to an affiliate (i.e., direct/indirect labor, fringe benefits, travel/housing, materials, supplies, indirect miscellaneous expenses, equipment/facilities charges, and overheads);
6) profit component of each arrangement/agreement where services are provided to an affiliate and how such component is determined;
7) comparable market values and documentation related to each arrangement/agreement;
8) percent/dollar amount of each affiliate arrangement/agreement charged to expense and/or capital accounts;
9) allocation bases/factors for allocated costs;
10) list and description of each utility asset transfer over $250,000; and
11) list by functional group of utility assets transfers valued less than $250,000.

RESPONSES:

1) LG&E and KU Services Company

2) Services Agreement Case No. PUA000050

3) January 1, 2001

4) $644,822,401.96

5) Component costs are:

Direct - Indirect Labor	$	42,958,190.34
Fringe Benefits/Overheads	$	50,091,547.55
Equipment/Facilities	$	15,864,254.33
Materials/Fuels	$	453,651,106.07
Outside Services	$	22,707,944.01
Indirect Miscellaneous Expenses (Vouchers)	$	21,693,925.16
Capital Expenditures	$	37,855,434.50
	$	644,822,401.96

6) LG&E and KU Services Company's cost allocation policies are to use at-cost pricing for affiliate transactions, without any profit component.

7) Transfers or sales of assets, goods or services between KU and LG&E and KU Services Company are priced at cost, which approximates market value.

8) All costs received from LG&E and KU Services Company are charged to the appropriate expense or capital account depending on the service performed for KU. Total Capital expense was 5.87% with a cost of $37,855,434.50 and total O&M expense was 94.13% with a cost of $606,966,967.46.

9) Allocation percentages for overhead calculations on labor as applicable in 2010 are as follows:

Part-Time Labor	92.61%
Temporary Labor	25.67%
Full-Time Labor	92.61%

Allocation percentages for overhead calculations on all labor from departments to which a vehicle is assigned for 2010 are as follows:

TRMS	2.70%

10) There were no utility asset transfers over $250,000.

11) There were no utility asset transfers under $250,000.

KENTUCKY UTILITIES COMPANY

ANNUAL REPORT OF AFFILIATE TRANSACTIONS WITH
LG&E AND KU SERVICES COMPANY (LG&E AND KU CAPITAL LLC)
January 1, 2010 - December 31, 2010

No. 11 Kentucky Utilities Company, d/b/a/ Old Dominion Power Company, shall file an Annual Report of Affiliate Transactions indirectly undertaken for the benefit of non-regulated affiliates with the Director of Public Utility Accounting of the Commission by no later than May 1 of each year, for the preceding calendar year, beginning May 1, 1999. Such report should include the following information:
1) non-regulated affiliate's name;
2) description of each type of service provided;
3) dates that each type of service was provided;
4) total dollar value (cost for each type of service provided);
5) component costs of each type of service provided (i.e., direct/indirect labor, fringe benefits, travel/housing, materials, supplies, Indirect miscellaneous expenses, equipment/facilities charges, and overheads);
6) profit component of each type of service and how profit component is determined; and
7) comparable market values and supporting documentation for each type of service provided.

RESPONSES:

1) LG&E and KU Services Company (LG&E and KU Capital LLC)

2) Compliance, Legal, and Environmental Affairs Services
Corporate Communications and Public Affairs Management Services
Corporate Finance and Treasury Services
Distribution Operations Services
Energy Services
HR Services
IT Organization Services
Regulatory Affairs and Government Affairs Management Services
Retail Business Services
Supply Chain and Logistics Services

3)

Compliance, Legal, and Environmental Affairs Services	April, July, August, September 2010
Corporate Communications and Public Affairs Management Services	July 2010
Corporate Finance and Treasury Services	June, August 2010
Distribution Operations Services	June 2010
Energy Services	March, September 2010
HR Services	April 2010
IT Organization Services	July, September, October 2010
Regulatory Affairs and Government Affairs Management Services	June, August, September, December 2010
Retail Business Services	April, June, August, September, October 2010
Supply Chain and Logistics Services	May 2010

4)

Compliance, Legal, and Environmental Affairs Services	$	36,246.85
Corporate Communications and Public Affairs Management Services	$	33,500.00
Corporate Finance and Treasury Services	$	123.29
Distribution Operations Services	$	9.38
Energy Services	$	62,741.16
HR Services	$	10,677.08
IT Organization Services	$	950.81
Regulatory Affairs and Government Affairs Management Services	$	820.44
Retail Business Services	$	2,049.94
Supply Chain and Logistics Services	$	2.80
	$	147,121.75

5) Component costs are:

Direct - Indirect Labor	$	(5,985.24)
Fringe Benefits/Overheads	$	-
Equipment/Facilities	$	98.00
Materials/Fuels	$	405.77
Outside Services	$	36,000.00
Indirect Miscellaneous Expenses (Vouchers)	$	84,141.80
Capital Expenditures	$	32,461.42
	$	147,121.75

6) LG&E and KU Services Company's cost allocation policies are to use at-cost pricing for affiliate transactions, without any profit component.

7) Transfers or sales of assets, goods or services between KU and LG&E and KU Services Company are priced at cost, which approximates market value.

Exhibit No. VASCC-2D

KENTUCKY UTILITIES COMPANY

ANNUAL REPORT OF AFFILIATE TRANSACTIONS WITH
LG&E AND KU SERVICES COMPANY (WESTERN KENTUCKY ENERGY CORP.)
January 1, 2010 - December 31, 2010

No. 11 Kentucky Utilities Company, d/b/a/ Old Dominion Power Company, shall file an Annual Report of Affiliate Transactions indirectly undertaken for the benefit of non-regulated affiliates with the Director of Public Utility Accounting of the Commission by no later than May 1 of each year, for the preceding calendar year, beginning May 1, 1999. Such report should include the following information:

1) non-regulated affiliate's name;
2) description of each type of service provided;
3) dates that each type of service was provided;
4) total dollar value (cost for each type of service provided);
5) component costs of each type of service provided (i.e., direct/indirect labor, fringe benefits, travel/housing, materials, supplies, indirect miscellaneous expenses, equipment/facilities charges, and overheads);
6) profit component of each type of service and how profit component is determined; and
7) comparable market values and supporting documentation for each type of service provided.

RESPONSES:

1) LG&E and KU Services Company (Western Kentucky Energy Corp.)

2) Distribution Operations Services
Energy Services
HR Services
Supply Chain and Logistics Services

3)

Distribution Operations Services	July 2010
Energy Services	March, August 2010
HR Services	October 2010
Supply Chain and Logistics Services	August 2010

4)

Distribution Operations Services	$	255.60
Energy Services	$	1,372.72
HR Services	$	4,938.00
Supply Chain and Logistics Services	$	(1,371.89)
	$	5,194.43

5) Component costs are:

Direct - Indirect Labor	$	6,565.49
Fringe Benefits/Overheads	$	-
Equipment/Facilities	$	-
Materials/Fuels	$	-
Outside Services	$	-
Indirect Miscellaneous Expenses (Vouchers)	$	(1,371.06)
Capital Expenditures	$	-
	$	5,194.43

6) LG&E and KU Services Company's cost allocation policies are to use at-cost pricing for affiliate transactions, without any profit component.

7) Transfers or sales of assets, goods or services between KU and LG&E and KU Services Company are priced at cost, which approximates market value

Exhibit No. VASCC-2E

KENTUCKY UTILITIES COMPANY

ANNUAL REPORT OF AFFILIATE TRANSACTIONS WITH
LG&E AND KU SERVICES COMPANY (LG&E ENERGY MARKETING INC.)
January 1, 2010 - December 31, 2010

No. 11 Kentucky Utilities Company, d/b/a/ Old Dominion Power Company, shall file an Annual Report of Affiliate Transactions indirectly undertaken for the benefit of non-regulated affiliates with the Director of Public Utility Accounting of the Commission by no later than May 1 of each year, for the preceding calendar year, beginning May 1, 1999. Such report should include the following information:
1) non-regulated affiliate's name;
2) description of each type of service provided;
3) dates that each type of service was provided;
4) total dollar value (cost for each type of service provided);
5) component costs of each type of service provided (i.e., direct/indirect labor, fringe benefits, travel/housing, materials, supplies, indirect miscellaneous expenses, equipment/facilities charges, and overheads);
6) profit component of each type of service and how profit component is determined; and
7) comparable market values and supporting documentation for each type of service provided.

RESPONSES:

1) LG&E and KU Services Company (LG&E Energy Marketing Inc.)

2) Audit Services
Energy Services
HR Services
IT Organization Services

3)

Audit Services	June 2010
Energy Services	March, June 2010
HR Services	June 2010
IT Organization Services	June 2010

4)

Audit Services	$	1,582 26
Energy Services	$	(1,632.91)
HR Services	$	103.41
IT Organization Services	$	0.16
	$	52.92

5) Component costs are:

Direct - Indirect Labor	$	(6,839.09)
Fringe Benefits/Overheads	$	-
Equipment/Facilities	$	-
Materials/Fuels	$	-
Outside Services	$	-
Indirect Miscellaneous Expenses (Vouchers)	$	1 24
Capital Expenditures	$	6,890.77
	$	52.92

6) LG&E and KU Services Company's cost allocation policies are to use at-cost pricing for affiliate transactions, without any profit component.

7) Transfers or sales of assets, goods or services between KU and LG&E and KU Services Company are priced at cost, which approximates market value.

KENTUCKY UTILITIES COMPANY

ANNUAL REPORT OF AFFILIATE TRANSACTIONS WITH
LG&E AND KU SERVICES COMPANY (LG&E INTERNATIONAL INC.)
January 1, 2010 - December 31, 2010

No. 11 Kentucky Utilities Company, d/b/a/ Old Dominion Power Company, shall file an Annual Report of Affiliate Transactions indirectly undertaken for the benefit of non-regulated affiliates with the Director of Public Utility Accounting of the Commission by no later than May 1 of each year, for the preceding calendar year, beginning May 1, 1999
Such report should include the following information:
1) non-regulated affiliate's name;
2) description of each type of service provided;
3) dates that each type of service was provided;
4) total dollar value (cost for each type of service provided);
5) component costs of each type of service provided (i.e., direct/indirect labor, fringe benefits, travel/housing, materials, supplies, indirect miscellaneous expenses, equipment/facilities charges, and overheads);
6) profit component of each type of service and how profit component is determined; and
7) comparable market values and supporting documentation for each type of service provided.

RESPONSES:

1) LG&E and KU Services Company (LG&E International Inc.)

2) HR Services

3) HR Services — October 2010

4) $ 152.00

5) Component costs are:

Direct - Indirect Labor	$	152.00
Fringe Benefits/Overheads	$	-
Equipment/Facilities	$	-
Materials/Fuels	$	-
Outside Services	$	-
Indirect Miscellaneous Expenses (Vouchers)	$	-
Capital Expenditures	$	-
	$	152.00

6) LG&E and KU Services Company's cost allocation policies are to use at-cost pricing for affiliate transactions, without any profit component.

7) Transfers or sales of assets, goods or services between KU and LG&E and KU Services Company are priced at cost, which approximates market value.

Exhibit No. VASCC-2G

KENTUCKY UTILITIES COMPANY

ANNUAL REPORT OF AFFILIATE TRANSACTIONS WITH
LG&E AND KU SERVICES COMPANY (LG&E AND KU ENERGY LLC)
January 1, 2010 - December 31, 2010

No. 11 Kentucky Utilities Company, d/b/a/ Old Dominion Power Company, shall file an Annual Report of Affiliate Transactions indirectly undertaken for the benefit of non-regulated affiliates with the Director of Public Utility Accounting of the Commission by no later than May 1 of each year, for the preceding calendar year, beginning May 1, 1999.
Such report should include the following information:
1) non-regulated affiliate's name;
2) description of each type of service provided;
3) dates that each type of service was provided;
4) total dollar value (cost for each type of service provided);
5) component costs of each type of service provided (i.e., direct/indirect labor, fringe benefits, travel/housing, materials, supplies, indirect miscellaneous expenses, equipment/facilities charges, and overheads);
6) profit component of each type of service and how profit component is determined; and
7) comparable market values and supporting documentation for each type of service provided.

RESPONSES:

1) LG&E and KU Services Company (LG&E and KU Energy LLC)

2) Corporate Finance and Treasury Services
Corporate Tax and Payroll Organization Services

3)

Corporate Finance and Treasury Services	January - December 2010
Corporate Tax and Payroll Organization Services	March, April, June, September, October 2010

4)

Corporate Finance and Treasury Services	$	119,485.21
Corporate Tax and Payroll Organization Services	$	94,339,264.64
	$	94,458,749.85

5) Component costs are:

Direct - Indirect Labor	$	-
Fringe Benefits/Overheads	$	-
Equipment/Facilities	$	-
Materials/Fuels	$	-
Outside Services	$	-
Indirect Miscellaneous Expenses (Vouchers)	$	119,485.21
Tax Settlements	$	94,339,264.64
Capital Expenditures	$	-
	$	94,458,749.85

6) LG&E and KU Services Company's cost allocation policies are to use at-cost pricing for affiliate transactions, without any profit component.

7) Transfers or sales of assets, goods or services between KU and LG&E and KU Services Company are priced at cost, which approximates market value.

KENTUCKY UTILITIES COMPANY

ANNUAL REPORT OF AFFILIATE TRANSACTIONS WITH
LG&E AND KU SERVICES COMPANY (PPL)
January 1, 2010 - December 31, 2010

No. 11 Kentucky Utilities Company, d/b/a/ Old Dominion Power Company, shall file an Annual Report of Affiliate Transactions indirectly undertaken for the benefit of non-regulated affiliates with the Director of Public Utility Accounting of the Commission by no later than May 1 of each year, for the preceding calendar year, beginning May 1, 1999. Such report should include the following information:

1) non-regulated affiliate's name;
2) description of each type of service provided;
3) dates that each type of service was provided;
4) total dollar value (cost for each type of service provided);
5) component costs of each type of service provided (i.e., direct/indirect labor, fringe benefits, travel/housing, materials, supplies, indirect miscellaneous expenses, equipment/facilities charges, and overheads);
6) profit component of each type of service and how profit component is determined; and
7) comparable market values and supporting documentation for each type of service provided.

RESPONSES:

1) LG&E and KU Services Company (PPL)

2) Corporate Finance and Treasury Services

3) Corporate Finance and Treasury Services — November - December 2010

4) $ 817,454.47

5) Component costs are:

Insurance Charges	$	57,553.16
Letter of Credit Fees	$	288.06
Debt Financing Fees	$	759,613.25
	$	817,454.47

6) LG&E and KU Services Company's cost allocation policies are to use at-cost pricing for affiliate transactions, without any profit component.

7) Transfers or sales of assets, goods or services between KU and LG&E and KU Services Company are priced at cost, which approximates market value.

KENTUCKY UTILITIES COMPANY

ANNUAL REPORT OF AFFILIATE TRANSACTIONS WITH LG&E AND KU SERVICES COMPANY (E.ON AG) January 1, 2010 - December 31, 2010

No. 11 Kentucky Utilities Company, d/b/a/ Old Dominion Power Company, shall file an Annual Report of Affiliate Transactions indirectly undertaken for the benefit of non-regulated affiliates with the Director of Public Utility Accounting of the Commission by no later than May 1 of each year, for the preceding calendar year, beginning May 1, 1999. Such report should include the following information:

1) non-regulated affiliate's name;
2) description of each type of service provided;
3) dates that each type of service was provided;
4) total dollar value (cost for each type of service provided);
5) component costs of each type of service provided (i.e., direct/indirect labor, fringe benefits, travel/housing, materials, supplies, indirect miscellaneous expenses, equipment/facilities charges, and overheads);
6) profit component of each type of service and how profit component is determined; and
7) comparable market values and supporting documentation for each type of service provided.

RESPONSES:

1) LG&E and KU Services Company (E.ON AG)

2) IT Organization Services
Finance and Corporate Development Services

3)

IT Organization Services	March 2010
Finance and Corporate Development Services	January - October 2010

4) $ 451,082.04

5) Component costs are:

Software Licenses	$	759,912.99
Direct - Indirect Labor	$	(308,830.95)
	$	451,082.04

6) LG&E and KU Services Company's cost allocation policies are to use at-cost pricing for affiliate transactions, without any profit component.

7) Transfers or sales of assets, goods or services between KU and LG&E and KU Services Company are priced at cost, which approximates market value.

KENTUCKY UTILITIES COMPANY

ANNUAL REPORT OF AFFILIATE TRANSACTIONS WITH
LG&E AND KU SERVICES INC. (E.ON ENGINEERING CORP)
January 1, 2010 - December 31, 2010

No. 11 Kentucky Utilities Company, d/b/a/ Old Dominion Power Company, shall file an Annual Report of Affiliate Transactions indirectly undertaken for the benefit of non-regulated affiliates with the Director of Public Utility Accounting of the Commission by no later than May 1 of each year, for the preceding calendar year, beginning May 1, 1999
Such report should include the following information:
1) non-regulated affiliate's name;
2) description of each type of service provided;
3) dates that each type of service was provided;
4) total dollar value (cost for each type of service provided);
5) component costs of each type of service provided (i.e., direct/indirect labor, fringe benefits, travel/housing, materials, supplies, indirect miscellaneous expenses, equipment/facilities charges, and overheads);
6) profit component of each type of service and how profit component is determined; and
7) comparable market values and supporting documentation for each type of service provided.

RESPONSES:
1) LG&E and KU Services Company (E.ON Engineering Corp)

2) Energy Services

3) Energy Services June 2010

4) $ 119,127.03

5) Component costs are:

Auxiliary Boiler Permit and Performance Testing	$	30,065.18
Coal Silo Baghouse Filter Testing for TC2	$	5,009.85
Ghent Catalyst Testing	$	61,600.00
Ghent SO3 Mitigation Testing	$	22,452.00
	$	119,127.03

6) LG&E and KU Services Company's cost allocation policies are to use at-cost pricing for affiliate transactions, without any profit component.

7) Transfers or sales of assets, goods or services between KU and LG&E and KU Services Company are priced at cost, which approximates market value.

Exhibit No VASCC-2K

KENTUCKY UTILITIES COMPANY

ANNUAL REPORT OF AFFILIATE TRANSACTIONS WITH
LG&E AND KU SERVICES COMPANY (E.ON ENGINEERING LIMITED)
January 1, 2010 - December 31, 2010

No 11 Kentucky Utilities Company, d/b/a/ Old Dominion Power Company, shall file an Annual Report of Affiliate Transactions indirectly undertaken for the benefit of non-regulated affiliates with the Director of Public Utility Accounting of the Commission by no later than May 1 of each year, for the preceding calendar year, beginning May 1, 1999.
Such report should include the following information:
1) non-regulated affiliate's name;
2) description of each type of service provided;
3) dates that each type of service was provided,
4) total dollar value (cost for each type of service provided);
5) component costs of each type of service provided (i.e., direct/indirect labor, fringe benefits, travel/housing, materials, supplies, indirect miscellaneous expenses, equipment/facilities charges, and overheads);
6) profit component of each type of service and how profit component is determined; and
7) comparable market values and supporting documentation for each type of service provided.

RESPONSES:

1) LG&E and KU Services Company (E.ON Engineering Limited)

2) Energy Services

3) Energy Services — January, September 2010

4) $ 49,989.00

5) Component costs are:

Engineering Support For Alstom Project	$	42,347.00
Engineering Work on Brown CT #6	$	7,642.00
	$	49,989.00

6) LG&E and KU Services Company's cost allocation policies are to use at-cost pricing for affiliate transactions, without any profit component.

7) Transfers or sales of assets, goods or services between KU and LG&E and KU Services Company are priced at cost, which approximates market value.

Exhibit No. VASCC-2L

KENTUCKY UTILITIES COMPANY

ANNUAL REPORT OF AFFILIATE TRANSACTIONS WITH
LG&E AND KU SERVICES COMPANY (E.ON IS GMBH)
January 1, 2010 - December 31, 2010

No. 11 Kentucky Utilities Company, d/b/a/ Old Dominion Power Company, shall file an Annual Report of Affiliate Transactions indirectly undertaken for the benefit of non-regulated affiliates with the Director of Public Utility Accounting of the Commission by no later than May 1 of each year, for the preceding calendar year, beginning May 1, 1999.
Such report should include the following information:
1) non-regulated affiliate's name;
2) description of each type of service provided;
3) dates that each type of service was provided;
4) total dollar value (cost for each type of service provided);
5) component costs of each type of service provided (i.e., direct/indirect labor, fringe benefits, travel/housing, materials, supplies, indirect miscellaneous expenses, equipment/facilities charges, and overheads);
6) profit component of each type of service and how profit component is determined; and
7) comparable market values and supporting documentation for each type of service provided

RESPONSES:

1) LG&E and KU Services Company (E.ON IS GmbH)

2) IT Organization Services

3) IT Organization Services — March, July 2010

4) $ 4,684.23

5) Component costs are:

Software Implementation	$	4,684.23
	$	4,684.23

6) LG&E and KU Services Company's cost allocation policies are to use at-cost pricing for affiliate transactions, without any profit component.

7) Transfers or sales of assets, goods or services between KU and LG&E and KU Services Company are priced at cost, which approximates market value.

Exhibit No VASCC-2M

KENTUCKY UTILITIES COMPANY

ANNUAL REPORT OF AFFILIATE TRANSACTIONS WITH
LG&E AND KU SERVICES COMPANY (E.ON UK)
January 1, 2010 - December 31, 2010

No. 11 Kentucky Utilities Company, d/b/a/ Old Dominion Power Company, shall file an Annual Report of Affiliate Transactions indirectly undertaken for the benefit of non-regulated affiliates with the Director of Public Utility Accounting of the Commission by no later than May 1 of each year, for the preceding calendar year, beginning May 1, 1999. Such report should include the following information:

1) non-regulated affiliate's name;
2) description of each type of service provided;
3) dates that each type of service was provided;
4) total dollar value (cost for each type of service provided);
5) component costs of each type of service provided (i.e., direct/indirect labor, fringe benefits, travel/housing, materials, supplies, indirect miscellaneous expenses, equipment/facilities charges, and overheads);
6) profit component of each type of service and how profit component is determined; and
7) comparable market values and supporting documentation for each type of service provided.

RESPONSES:

1) LG&E and KU Services Company (E.ON UK)

2) Retail Business Services

3) Retail Business Services — January, February, March, June 2010

4) $ 7,463.67

5) Component costs are:

Direct - Indirect Labor	$ 7,463.67
	$ 7,463.67

6) LG&E and KU Services Company's cost allocation policies are to use at-cost pricing for affiliate transactions, without any profit component

7) Transfers or sales of assets, goods or services between KU and LG&E and KU Services Company are priced at cost, which approximates market value.

ENTITY EVENTS

1. KU Solutions Corporation merged into E.ON U.S. Capital Corp on February 26, 2010.
2. E.ON U.S. Foundation Inc. changed its name to LG&E and KU Foundation Inc. on September 27, 2010.
3. E.ON U.S. Services changed its name to LG&E and KU Services Company on September 30, 2010.
4. E.ON U.S. LLC changed its name to LG&E and KU Energy LLC on November 1, 2010.
5. E.ON U.S. Capital Corp changed its name to LG&E and KU Capital Corp. on November 1, 2010.
6. E.ON U.S. Hydro I LLC changed its name to LG&E and KU Hydro I LLC on November 1, 2010.
7. LG&E and KU Capital Corp. converted to a limited liability company, LG&E and KU Capital LLC on November 29, 2010.
8. LG&E Power Inc. was merged into LG&E and KU Capital LLC on December 17, 2010.
9. LG&E Power Argentina I, Inc. merged into LG&E International Inc. on December 17, 2010.
10. LG&E Power Argentina II Inc. merged into LG&E International Inc. on December 17, 2010.
11. LG&E Power Development Inc. merged into LG&E and KU Capital LLC on December 17, 2010.
12. LG&E Power Operations Inc. merged into LG&E and KU Capital LLC on December 17, 2010

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

Form 60 Approved
OMB No. 1902-0215
Expires 01/31/2013

FERC FINANCIAL REPORT
FERC FORM No. 60: Annual Report of Centralized Service Companies

This report is mandatory under the Public Utility Holding Company Act of 2005, Section 1270, Section 309 of the Federal Power Act and 18 C.F.R. § 366.23. 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 this report to be of a confidential nature.

Exact Legal Name of Respondent (Company)	**Year of Report**
LG&E and KU Services Company	**Dec 31,** 2010

GENERAL INSTRUCTIONS FOR FILING FERC FORM NO. 60

I. Purpose

Form No. 60 is an annual regulatory support requirement under 18 CFR 369.1for centralized service companies. The report is designed to collect financial information from centralized service companies subject to the jurisdiction of the Federal Energy Regulatory Commission. The report is considered to be a non-confidential public use form.

II. Who Must Submit

Unless the holding company system is exempted or granted a waiver by Commission rule or order pursuant to §§ 18 CFR 366.3 and 366.4 of this chapter, every centralized service company (see § 367.2) in a holding company system must prepare and file electronically with the Commission the FERC Form No. 60 then in effect pursuant to the General Instructions set out in this form.

III. How to Submit

Submit FERC Form No. 60 electronically through the Form No. 60 Submission Software. Retain one copy of each report for your files. For any resubmissions, submit the filing using the Form No. 60 Submission Software including a justification. Respondents must submit the Corporate Officer Certification electronically.

IV. When to Submit

Submit FERC Form No. 60 according to the filing date contained § 18 CFR 369.1 of the Commission's regulations.

V. Preparation

Prepare this report in conformity with the Uniform System of Accounts (18 CFR 367) (USof A). Interpret all accounting words and phrases in accordance with the USof A.

VI. Time Period

This report covers the entire calendar year.

VII. Whole Dollar Usage

Enter in whole numbers (dollars) only, except where otherwise noted. 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 amounts.

VIII. Accurateness

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.

IX. Applicability

For any page(s) that is not applicable to the respondent, enter "NONE," or "Not Applicable" in column (c) on the List of Schedules, page 2.

X. Date Format

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

XI. Number Format

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 use of a minus sign.

XII. Required Entries

Do not make references to reports of previous years or to other reports instead of required entries, except as specifically authorized.

XIII. Prior Year References

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

XIV. Where to Send Comments on Public Reporting Burden

The public reporting burden for the Form No. 60 collection of information is estimated to average 75 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.

Send comments regarding these burden estimates or any aspect of this collection of information, including suggestions for reducing burden, to:

Federal Energy Regulatory Commission,
888 First Street NE
Washington, DC 20426
(Attention: Mr. Michael Miller, ED-33);

And to:

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)).

DEFINITIONS
I. Respondent -- The person, corporation, or other legal entity in whose behalf the report is made.

FERC FORM NO. 60
ANNUAL REPORT FOR SERVICE COMPANIES

IDENTIFICATION

01 Exact Legal Name of Respondent LG&E and KU Services Company	02 Year of Report Dec 31, 2010
03 Previous Name (If name changed during the year) E. ON U.S. Services Inc.	04 Date of Name Change 11/01/2010
05 Address of Principal Office at End of Year (Street, City, State, Zip Code) 220 West Main Street, Louisville, KY 40202	06 Name of Contact Person Eric Raible
07 Title of Contact Person Manager Regulatory Accounting and Reporting	08 Address of Contact Person 220 West Main Street, Louisville, KY 40202
09 Telephone Number of Contact Person (502) 627-3426	10 E-mail Address of Contact Person eric.raible@lge-ku.com
11 This Report is: (1) [X] An Original (2) [ ] A Resubmission	12 Resubmission Date (Month, Day, Year) / /
13 Date of Incorporation 06/02/2000	14 If Not Incorporated, Date of Organization / /

15 State or Sovereign Power Under Which Incorporated or Organized

KENTUCKY

16 Name of Principal Holding Company Under Which Reporting Company is Organized:

PPL Corporation

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.

17 Name of Signing Officer S. Bradford Rives	19 Signature of Signing Officer S. Bradford Rives	20 Date Signed (Month, Day, Year) 04/29/2011
18 Title of Signing Officer Chief Financial Officer		

Name of Respondent	This Report Is:	Resubmission Date (Mo, Da, Yr)	Year/Period of Report
LG&E and KU Services Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	Dec 31, 2010

List of Schedules and Accounts

1. Enter in Column (c) the terms "None" or "Not Applicable" as appropriate, where no information or amounts have been reported for certain pages.

Line No.	Description (a)	Page Reference (b)	Remarks (c)
1	Schedule I - Comparative Balance Sheet	101-102	
2	Schedule II - Service Company Property	103	
3	Schedule III - Accumulated Provision for Depreciation and Amortization of Service Company Property	104	
4	Schedule IV - Investments	105	None
5	Schedule V - Accounts Receivable from Associate Companies	106	
6	Schedule VI - Fuel Stock Expenses Undistributed	107	
7	Schedule VII - Stores Expense Undistributed	108	
8	Schedule VIII - Miscellaneous Current and Accrued Assets	109	None
9	Schedule IX - Miscellaneous Deferred Debits	110	None
10	Schedule X - Research, Development, or Demonstration Expenditures	111	None
11	Schedule XI - Proprietary Capital	201	
12	Schedule XII - Long-Term Debt	202	None
13	Schedule XIII - Current and Accrued Liabilities	203	
14	Schedule XIV - Notes to Financial Statements	204	
15	Schedule XV - Comparative Income Statement	301-302	
16	Schedule XVI - Analysis of Charges for Service - Associate and Nonassociate Companies	303-306	
17	Schedule XVII - Analysis of Billing – Associate Companies (Account 457)	307	
18	Schedule XVIII – Analysis of Billing – Non-Associate Companies (Account 458)	308	None
21	Schedule XIX - Miscellaneous General Expenses - Account 930.2	307	
23	Schedule XX - Organization Chart	401	
24	Schedule XXI - Methods of Allocation	402	

Name of Respondent	This Report Is:	Resubmission Date (Mo, Da, Yr)	Year/Period of Report
LG&E and KU Services Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	Dec 31, 2010

Schedule I - Comparative Balance Sheet

1. Give balance sheet of the Company as of December 31 of the current and prior year.

Line No.	Account Number (a)	Description (b)	Reference Page No. (c)	As of Dec 31 Current (d)	As of Dec 31 Prior (e)
1		**Service Company Property**			
2	101	Service Company Property	103	2,276,934	1,906,460
3	101.1	Property Under Capital Leases	103		
4	106	Completed Construction Not Classified			
5	107	Construction Work In Progress	103	679,518	700,225
6		Total Property (Total Of Lines 2-5)		2,956,452	2,606,685
7	108	Less: Accumulated Provision for Depreciation of Service Company Property	104	548,921	754,670
8	111	Less: Accumulated Provision for Amortization of Service Company Property			
9		Net Service Company Property (Total of Lines 6-8)		2,407,531	1,852,015
10		**Investments**			
11	123	Investment In Associate Companies	105		
12	124	Other Investments	105		
13	128	Other Special Funds	105		
14		Total Investments (Total of Lines 11-13)			
15		**Current And Accrued Assets**			
16	131	Cash			
17	134	Other Special Deposits			
18	135	Working Funds			
19	136	Temporary Cash Investments			
20	141	Notes Receivable		100,127,427	
21	142	Customer Accounts Receivable			
22	143	Accounts Receivable		288,089	365,863
23	144	Less: Accumulated Provision for Uncollectible Accounts			
24	146	Accounts Receivable From Associate Companies	106	109,655,512	99,271,618
25	152	Fuel Stock Expenses Undistributed	107		
26	154	Materials And Supplies			
27	163	Stores Expense Undistributed	108		
28	165	Prepayments		5,855,627	4,974,165
29	171	Interest And Dividends Receivable			
30	172	Rents Receivable			
31	173	Accrued Revenues			
32	174	Miscellaneous Current and Accrued Assets			
33	175	Derivative Instrument Assets	109		
34	176	Derivative Instrument Assets – Hedges			
35		Total Current and Accrued Assets (Total of Lines 16-34)		215,926,655	104,611,646
36		**Deferred Debits**			
37	181	Unamortized Debt Expense			
38	182.3	Other Regulatory Assets			
39	183	Preliminary Survey And Investigation Charges			
40	184	Clearing Accounts		4,152	8,542
41	185	Temporary Facilities			
42	186	Miscellaneous Deferred Debits			
43	188	Research, Development, or Demonstration Expenditures	110		
44	189	Unamortized loss on reacquired debt	111		
45	190	Accumulated Deferred Income Taxes		79,467,990	74,514,307
46		Total Deferred Debits (Total of Lines 37-45)		79,472,142	74,522,849
47		TOTAL ASSETS AND OTHER DEBITS (TOTAL OF LINES 9, 14, 35 and 46)		297,806,328	180,986,510

Name of Respondent	This Report Is:	Resubmission Date (Mo, Da, Yr)	Year/Period of Report
LG&E and KU Services Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	Dec 31, 2010

Schedule I - Comparative Balance Sheet (continued)

Line No.	Account Number (a)	Description (b)	Reference Page No. (c)	As of Dec 31 Current (d)	As of Dec 31 Prior (e)
48		**Proprietary Capital**			
49	201	Common Stock Issued	201	100	100
50	204	Preferred Stock Issued	201		
51	211	Miscellaneous Paid-In-Capital	201	15,457,130	900
52	215	Appropriated Retained Earnings	201		
53	216	Unappropriated Retained Earnings	201	55,874	
54	219	Accumulated Other Comprehensive Income	201	5,339,505	(64,660,600)
55		Total Proprietary Capital (Total of Lines 49-54)		20,852,609	(64,659,600)
56		**Long-Term Debt**			
57	223	Advances From Associate Companies	202		
58	224	Other Long-Term Debt	202		
59	225	Unamortized Premium on Long-Term Debt			
60	226	Less: Unamortized Discount on Long-Term Debt-Debit			
61		Total Long-Term Debt (Total of Lines 57-60)			
62		Other Non-current Liabilities			
63	227	Obligations Under Capital Leases-Non-current			
64	228.2	Accumulated Provision for Injuries and Damages			
65	228.3	Accumulated Provision For Pensions and Benefits		211,373,706	174,115,353
66	230	Asset Retirement Obligations			
67		Total Other Non-current Liabilities (Total of Lines 63-66)		211,373,706	174,115,353
68		**Current and Accrued Liabilities**			
69	231	Notes Payable			
70	232	Accounts Payable		37,734,648	27,914,161
71	233	Notes Payable to Associate Companies	203		
72	234	Accounts Payable to Associate Companies	203	8,116,068	4,099,119
73	236	Taxes Accrued		(12,811,619)	991,440
74	237	Interest Accrued			
75	241	Tax Collections Payable		596,503	279,344
76	242	Miscellaneous Current and Accrued Liabilities	203	14,806,188	17,864,571
77	243	Obligations Under Capital Leases – Current			
78	244	Derivative Instrument Liabilities			
79	245	Derivative Instrument Liabilities – Hedges			
80		Total Current and Accrued Liabilities (Total of Lines 69-79)		48,441,788	51,148,635
81		**Deferred Credits**			
82	253	Other Deferred Credits		17,033,845	20,277,742
83	254	Other Regulatory Liabilities			
84	255	Accumulated Deferred Investment Tax Credits			
85	257	Unamortized Gain on Reacquired Debt			
86	282	Accumulated deferred income taxes-Other property			
87	283	Accumulated deferred income taxes-Other		104,380	104,380
88		Total Deferred Credits (Total of Lines 82-87)		17,138,225	20,382,122
89		TOTAL LIABILITIES AND PROPRIETARY CAPITAL (TOTAL OF LINES 55, 61, 67, 80, AND 88)		297,806,328	180,986,510

Schedule Page: 101 Line No.: 20 Column: d

$100,127,427 is Notes Receivable From Associate Companies - Account 145. Account 145 is not included in the balance sheet so the amount was moved to Account 141 - Notes Receivable.

Schedule Page: 101 Line No.: 45 Column: d

The majority of the note below provides a summary of all the purchase accounting adjustments included in the financial statements for LG&E and KU Services Company ("Servco"). These descriptions are provided as early as possible in this document as these descriptions relate to many separate disclosures of purchase accounting adjustments and are intended to prevent repetition throughout the document.

On November 1, 2010, PPL Corporation ("PPL") completed its acquisition of LG&E and KU Energy LLC ("LKE") (formerly E.ON U.S. LLC) and its subsidiaries including Servco (formerly E.ON U.S. Services Inc.). The push-down basis of accounting was used to record the fair value adjustments of assets and liabilities on LKE at the acquisition date. PPL paid a cash consideration for LKE and its subsidiaries of $2,493 million as well as a capital contribution on November 1, 2010, of $1,565 million.

Note which relates specifically to Accumulated Deferred Income Taxes (190):

The balance in Accumulated Deferred Income Taxes (190) was adjusted due to the purchase of Servco's parent by PPL in November 2010. The purchase accounting adjustment was to reflect the deferred income tax impact of purchase accounting adjustments related to pensions as of the ~uisition date. The following reflects the purchase accounting adjustment:

Accumulated Deferred Income Taxes (190) Without Purchase Accounting	$ 82,202,022
Purchase Accounting Adjustment - Pension and postretirement benefits	(2,734,032)
Total for Accumulated Deferred Income Taxes (190)	$ 79,467,990

Schedule Page: 101 Line No.: 51 Column: d

The balance in Miscellaneous Paid-In-Capital (211) was adjusted due to the purchase of Servco's parent by PPL in November 2010. To reflect the fair value, the balance was adjusted for pensions net of deferred taxes. The balance also includes elimination of Other Comprehensive Income and Retained Earnings at October 31, 2010. The following reflects the purchase accounting adjustment:

Miscellaneous Paid-In-Capital (211) Without Purchase Accounting	$ 100,000,900
Purchase Accounting Adjustment - Elimination of OCI relating to pension and other postretirement benefits	(138,405,489)
Purchase Accounting Adjustment - Tax on OCI relating to pension and other postretirement benefits	53,839,736
Purchase Accounting Adjustment - Prior retained earnings	21,983
Total for Miscellaneous Paid-In-Capital (211)	$ 15,457,130

Schedule Page: 101 Line No.: 53 Column: d

The balance in Unappropriated Retained Earnings (216) was adjusted due to the purchase of Servco's parent by PPL in November 2010. The following reflects the purchase accounting adjustment:

Unappropriated Retained Earnings (216) Without Purchase Accounting	$ 77,857
Purchase Accounting Adjustment	(21,983)
Total for Unappropriated Retained Earnings (216)	$ 55,874

Schedule Page: 101 Line No.: 54 Column: d

The balance in Accumulated Other Comprehensive Income (219) was adjusted due to the purchase of Servco's parent by PPL Corporation in November 2010. The following reflects the purchase accounting adjustment:

Other Comprehensive Income (219) Without Purchase Accounting	$ (137,373,935)
Purchase Accounting Adjustment - Elimination of OCI relating to pension and other postretirement benefits	138,405,489
November & December OCI - Pension and other postretirement benefits	8,108,680
Deferred tax on OCI	(3,800,729)
Total for Accumulated Other Comprehensive Income (219)	$ 5,339,505

S--hedule Page: 101 Line No.: 65 Column: d

balance in Accumulated Provision For Pensions and Benefits (228.3) was adjusted due to the purchase of Servco's parent by PPL in November 2010. Adjustments were made to record pension assets at fair value and remeasure pension and postretirement benefit obligations at current discount rates. The following reflects the purchase accounting adjustment:

Accumulated Provision For Pensions and Benefits (228.3) Without Purchase Accounting	$ 218,402,066
Purchase Accounting Adjustment	(7,028,360)
Total for Accumulated Provision For Pensions and Benefits (228.3)	$ 211,373,706

Schedule Page: 101 Line No.: 73 Column: d

Balance due to timing of estimated federal tax payments made in 2010. At the end of 2010, Servco had overpaid the estimated tax liability.

Name of Respondent	This Report Is:	Resubmission Date (Mo, Da, Yr)	Year/Period of Report
LG&E and KU Services Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	Dec 31, 2010

Schedule II - Service Company Property

1. Provide an explanation of Other Changes recorded in Column (f) considered material in a footnote.
2. Describe each construction work in progress on lines 18 through 30 in Column (b).

Line No.	Acct # (a)	Title of Account (b)	Balance at Beginning of Year (c)	Additions (d)	Retirements or Sales (e)	Other Changes (f)	Balance at End of Year (g)
1	301	Organization					
2	303	Miscellaneous Intangible Plant					
3	306	Leasehold Improvements					
4	389	Land and Land Rights					
5	390	Structures and Improvements					
6	391	Office Furniture and Equipment	1,906,460	1,044,119	673,645		2,276,934
7	392	Transportation Equipment					
8	393	Stores equipment					
9	394	Tools, Shop and Garage Equipment					
10	395	Laboratory Equipment					
11	396	Power Operated Equipment					
12	397	Communications Equipment					
13	398	Miscellaneous Equipment					
14	399	Other Tangible Property					
15	399.1	Asset Retirement Costs					
16		**Total Service Company Property (Total of Lines 1-15)**	1,906,460	1,044,119	673,645		2,276,934
17	107	**Construction Work in Progress:**					
18		Office Furniture and Equipment	700,225	1,023,412		(1,044,119)	679,518
19							
20							
21							
22							
23							
24							
25							
26							
27							
28							
29							
30							
31		**Total Account 107 (Total of Lines 14-30)**	700,225	1,023,412		(1,044,119)	679,518
32		**Total (Lines 16 and Line 31)**	2,606,685	2,067,531		(1,044,119)	2,956,452

Name of Respondent	This Report is:	Resubmission Date (Mo, Da, Yr)	Year of Report
LG&E and KU Services Company	(1) X An Original (2) _ A Resubmission	/ /	2010

FOOTNOTE DATA

Schedule Page: 103 Line No.: 18 Column: f

$1,044,119 was transferred from Construction Work in Process to Service Company Property.

Name of Respondent	This Report Is:	Resubmission Date (Mo, Da, Yr)	Year/Period of Report
LG&E and KU Services Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	Dec 31, 2010

Schedule III – Accumulated Provision for Depreciation and Amortization of Service Company Property

1. Provide an explanation of Other Charges in Column (f) considered material in a footnote.

Line No.	Account Number (a)	Description (b)	Balance at Beginning of Year (c)	Additions Charged To Account 403-403.1 404-405 (d)	Retirements (e)	Other Changes Additions (Deductions) (f)	Balance at Close of Year (g)
1	301	Organization					
2	303	Miscellaneous Intangible Plant					
3	306	Leasehold Improvements					
4	389	Land and Land Rights					
5	390	Structures and Improvements					
6	391	Office Furniture and Equipment	754,670	467,896	673,645		548,921
7	392	Transportation Equipment					
8	393	Stores equipment					
9	394	Tools, Shop and Garage Equipment					
10	395	Laboratory Equipment					
11	396	Power Operated Equipment					
12	397	Communications Equipment					
13	398	Miscellaneous Equipment					
14	399	Other Tangible Property					
15	399.1	Asset Retirement Costs					
16		**Total**	754,670	467,896	673,645		548,921

Name of Respondent	This Report Is:	Resubmission Date (Mo, Da, Yr)	Year/Period of Report
LG&E and KU Services Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	Dec 31, 2010

Schedule IV -- Investments

1. For other investments (Account 124) and other special funds (Account128), in a footnote state each investment separately, with description including the name of issuing company, number of shares held or principal investment amount.
2. For temporary cash investments (Account 136), list each investment separately in a footnote.
3. Investments less than $50,000 may be grouped, showing the number of items in each group.

Line No.	Account Number (a)	Title of Account (b)	Balance at Beginning of Year (c)	Balance at Close of Year (d)
1	123	Investment In Associate Companies		
2	124	Other Investments		
3	128	Other Special Funds		
4	136	Temporary Cash Investments		
5		(Total of Lines 1-4)		

Name of Respondent	This Report Is:	Resubmission Date (Mo, Da, Yr)	Year/Period of Report
LG&E and KU Services Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	Dec 31, 2010

Schedule V – Accounts Receivable from Associate Companies

1. List the accounts receivable from each associate company.
2. If the service company has provided accommodation or convenience payments for associate companies, provide in a separate footnote a listing of total payments for each associate company.

Line No.	Account Number (a)	Title of Account (b)	Balance at Beginning of Year (c)	Balance at Close of Year (d)
1	146	**Accounts Receivable From Associate Companies**		
2		**Associate Company:**		
3		E.ON AG	179,890	
4		E.ON Energie AF	4,791	
5		E.ON Kraftwerke GmbH	43,420	
6		E.ON Sverige AB	8,772	
7		PPL Corporation		1,664,150
8		LG&E and KU Capital LLC	61,532,359	64,589,610
9		FCD LLC	197	300
10		Kentucky Utilities Company	19,745,555	23,249,986
11		LG&E Energy Marketing	74	
12		LG&E International Inc.	115,298	768
13		Louisville Gas and Electric Company	17,398,998	19,944,791
14		Western Kentucky Energy Corp.	242,264	205,907
15				
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38				
39		Analysis of Accomodation or Convenience Payments - see footnote		
40	**Total**		99,271,618	109,655,512

Schedule Page: 106 Line No.: 8 Column: b

Formerly E.ON U.S. Capital Corp.

Schedule Page: 106 Line No.: 39 Column: b

Analysis of convenience or accomodation payments:

Associate Company	**Amount**
LG&E and KU Capital LLC	$ 412,557
Kentucky Utilities Company	457,677,215
LG&E International Inc.	7,300
Louisville Gas and Electric Company	420,033,892
Western Kentucky Energy Corp.	417,553
Total	$878,548,517

Convenience payments resulted primarily from the following:

Description	**Amount**
401(k) Plan	$ 5,537,903
Coal, Fuel Oil, and Limestone Purchases	840,340,530
Dental Claims	334,151
Human Resources Consulting Services	508,905
Life Insurance	966,227
Life Insurance - Retirees	331,120
Long-Term Disability Insurance	575,091
Medical Claims	5,352,853
Medical Claims - Retirees	11,293,400
Miscellaneous Expenses	5,520
Other Benefits	1,401,322
Property Insurance	10,401,820
Retirement Income	277,807
Workers' Compensation Claims	918,255
Workers' Compensation Insurance	303,613
Total	$878,548,517

Name of Respondent	This Report Is:	Resubmission Date (Mo, Da, Yr)	Year/Period of Report
LG&E and KU Services Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	Dec 31, 2010

Schedule VI – Fuel Stock Expenses Undistributed

1. List the amount of labor in Column (c) and expenses in Column (d) incurred with respect to fuel stock expenses during the year and indicate amount attributable to each associate company.
2. In a separate footnote, describe in a narrative the fuel functions performed by the service company.

Line No.	Account Number (a)	Title of Account (b)	Labor (c)	Expenses (d)	Total (e)
1	152	Fuel Stock Expenses Undistributed			
2		Associate Company:			
3		None		0	
4					
5					
6					
7					
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37					
38					
39					
40	Total				

Schedule Page: 107 Line No.: 3 Column: d

Fuel functions provided by Servco include the following which are largely provided by Servco as an administrative agent, paying agent or other representative capacity, for the respective affiliate(s):

- Procurement of coal, fuel oil, scrubber reagent, ammonia, and SO3 mitigation chemicals
- Transportation service to move these commodities from the loading point to the power plant
- Monitoring of quality, inventory level, and forecasted requirements
- Making purchases as needed on a timely basis
- Preparing bid solicitation for coal, and other commodities, as necessary, and evaluating those bids
- Negotiating and writing the contracts and purchase orders
- Contract administration

Name of Respondent	This Report Is:	Resubmission Date (Mo, Da, Yr)	Year/Period of Report
LG&E and KU Services Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	Dec 31, 2010

Schedule VII – Stores Expense Undistributed

1. List the amount of labor in Column (c) and expenses in Column (d) incurred with respect to stores expense during the year and indicate amount attributable to each associate company.

Line No.	Account Number (a)	Title of Account (b)	Labor (c)	Expenses (d)	Total (e)
1	163	Stores Expense Undistributed			
2		Associate Company:			
3		None		0	
4					
5					
6					
7					
8					
9					
10					
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39					
40	**Total**				

Schedule Page: 108 Line No.: 3 Column: d

Stores Expense was fully distributed for 2010.

Associate Company		Expenses
LG&E and KU Capital LLC	$	6,874
Kentucky Utilities Company		121,157
Louisville Gas and Electric Company		159,350
Western Kentucky Energy Corp.		185
Total	$	287,566

Name of Respondent	This Report Is:	Resubmission Date (Mo, Da, Yr)	Year/Period of Report
LG&E and KU Services Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	Dec 31, 2010

Schedule VIII - Miscellaneous Current and Accrued Assets

1. Provide detail of items in this account. Items less than $50,000 may be grouped, showing the number of items in each group.

Line No.	Account Number (a)	Title of Account (b)	Balance at Beginning of Year (c)	Balance at Close of Year (d)
1	174	Miscellaneous Current and Accrued Assets		
2		Item List:		
3		None		
4				
5				
6				
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9				
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38				
39				
40	Total			

Name of Respondent LG&E and KU Services Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Resubmission Date (Mo, Da, Yr) / /	Year/Period of Report Dec 31, 2010

Schedule IX - Miscellaneous Deferred Debits

1. Provide detail of items in this account. Items less than $50,000 may be grouped, showing the number of items in each group.

Line No.	Account Number (a)	Title of Account (b)	Balance at Beginning of Year (c)	Balance at Close of Year (d)
1	186	Miscellaneous Deferred Debits		
2		Items List:		
3		None		
4				
5				
6				
7				
8				
9				
10				
11				
12				
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37				
38				
39				
40	**Total**			

Name of Respondent	This Report Is:	Resubmission Date (Mo, Da, Yr)	Year/Period of Report
LG&E and KU Services Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	Dec 31, 2010

Schedule X - Research, Development, or Demonstration Expenditures

1. Describe each material research, development, or demonstration project that incurred costs by the service corporation during the year. Items less than $50,000 may be grouped, showing the number of items in each group.

Line No.	Account Number (a)	Title of Account (b)	Amount (c)
1	188	Research, Development, or Demonstration Expenditures	
2		Project List:	
3		None	
4			
5			
6			
7			
8			
9			
10			
11			
12			
13			
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38			
39			
40	**Total**		

Name of Respondent	This Report Is:	Resubmission Date (Mo, Da, Yr)	Year/Period of Report
LG&E and KU Services Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	Dec 31, 2010

Schedule XI - Proprietary Capital

1. For miscellaneous paid-in capital (Account 211) and appropriate retained earnings (Account 215), classify amounts in each account, with a brief explanation, disclosing the general nature of transactions which give rise to the reported amounts.
2. For the unappropriated retained earnings (Account 216), in a footnote, give particulars concerning net income or (loss) during the year, distinguishing between compensation for the use of capital owed or net loss remaining from servicing nonassociates per the General Instructions of the Uniform System of Accounts. For dividends paid during the year in cash or otherwise, provide rate percentages, amount of dividend, date declared and date paid.

Line No.	Account Number (a)	Title of Account (b)	Description (c)	Amount (d)
1	201	Common Stock Issued	Number of Shares Authorized	1,000
2			Par or Stated Value per Share	
3			Outstanding Number of Shares	100
4			Close of Period Amount	100
5		Preferred Stock Issued	Number of Shares Authorized	
6			Par or Stated Value per Share	
7			Outstanding Number of Shares	
8			Close of Period Amount	
9	211	Miscellaneous Paid-In Capital		15,457,130
10	215	Appropriated Retained Earnings		
11	219	Accumulated Other Comprehensive Income		5,339,505
12	216	Unappropriated Retained Earnings	Balance at Beginning of Year	
13			Net Income or (Loss)	55,874
14			Dividend Paid	
15			Balance at Close of Year	55,874

Schedule Page: 201 Line No.: 9 Column: d

The balance in Miscellaneous Paid-In-Capital (211) was adjusted due to the purchase of Servco's parent by PPL in November 2010. To reflect the fair value, the balance was adjusted for pensions net of deferred taxes. The balance also includes elimination of Other Comprehensive Income and Retained Earnings at October 31, 2010. The following reflects the purchase accounting adjustment:

Miscellaneous Paid-In-Capital (211) Without Purchase Accounting	$ 100,000,900
Purchase Accounting Adjustment - Elimination of OCI relating to pension and other postretirement benefits	(138,405,489)
Purchase Accounting Adjustment - Tax on OCI relating to pension and other postretirement benefits	53,839,736
Purchase Accounting Adjustment - Prior retained earnings	21,983
Total for Miscellaneous Paid-In-Capital (211)	$ 15,457,130

Schedule Page: 201 Line No.: 11 Column: d

The balance in Accumulated Other Comprehensive Income (219) was adjusted due to the purchase of Servco's parent by PPL Corporation in November 2010. The following reflects the purchase accounting adjustment:

Other Comprehensive Income (219) Without Purchase Accounting	$ (137,373,935)
Purchase Accounting Adjustment - Elimination of OCI relating to pension and other postretirement benefits	138,405,489
November & December OCI - Pension and other postretirement benefits	8,108,680
Deferred tax on OCI	(3,800,729)
Total for Accumulated Other Comprehensive Income (219)	$ 5,339,505

Schedule Page: 201 Line No.: 13 Column: d

The balance in Unappropriated Retained Earnings (216) was adjusted due to the purchase of Servco's parent by PPL in November 2010. The following reflects the purchase accounting adjustment:

Unappropriated Retained Earnings (216) Without Purchase Accounting	$ 77,857
Purchase Accounting Adjustment	(21,983)
Total for Unappropriated Retained Earnings (216)	$ 55,874

Name of Respondent	This Report Is:	Resubmission Date (Mo, Da, Yr)	Year/Period of Report
LG&E and KU Services Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	Dec 31, 2010

Schedule XII -- Long Term Debt

1. For the advances from associate companies (Account 223), describe in a footnote the advances on notes and advances on open accounts. Names of associate companies from which advances were received shall be shown under the class and series of obligation in Column (c).
2. For the deductions in Column (h), please give an explanation in a footnote.
3. For other long-term debt (Account 224), list the name of the creditor company or organization in Column (b).

Line No.	Account Number (a)	Title of Account (b)	Term of Obligation Class & Series of Obligation (c)	Date of Maturity (d)	Interest Rate (e)	Amount Authorized (f)	Balance at Beginning of Year (g)	Additions Deductions (h)	Balance at Close of Year (i)
1	223	Advances from Associate Companies							
2		Associate Company:							
3									
4									
5									
6									
7									
8									
9									
10									
11									
12									
13		TOTAL							
14	224	Other Long-Term Debt							
15		List Creditor:							
16									
17									
18									
19									
20									
21									
22									
23									
24									
25									
26									
27									
28		TOTAL							

Name of Respondent LG&E and KU Services Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Resubmission Date (Mo, Da, Yr) / /	Year/Period of Report Dec 31, 2010

Schedule XIII – Current and Accrued Liabilities

1. Provide the balance of notes and accounts payable to each associate company (Accounts 233 and 234).
2. Give description and amount of miscellaneous current and accrued liabilities (Account 242). Items less than $50,000 may be grouped, showing the number of items in each group.

Line No.	Account Number (a)	Title of Account (b)	Balance at Beginning of Year (c)	Balance at Close of Year (d)
1	233	Notes Payable to Associates Companies		
2				
3				
4				
5				
6				
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11				
12				
13				
14				
15				
16				
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19				
20				
21				
22				
23				
24	234	Accounts Payable to Associate Companies	4,099,119	8,116,068
25				
26				
27				
28				
29				
30				
31				
32				
33				
34				
35				
36				
37				
38				
39				
40				
41	242	Miscellaneous Current and Accrued Liabilities	17,864,571	14,806,188
42				
43				
44				
45				
46				
47				
48				
49				

Name of Respondent LG&E and KU Services Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Resubmission Date (Mo, Da, Yr) / /	Year/Period of Report Dec 31, 2010

Schedule XIII – Current and Accrued Liabilities (continued)

Line No.	Account Number (a)	Title of Account (b)	Balance at Beginning of Year (c)	Balance at Close of Year (d)
50		(Total)	21,963,690	22,922,256

Name of Respondent LG&E and KU Services Company	This Report is: (1) X An Original (2) __ A Resubmission	Resubmission Date (Mo, Da, Yr) / /	Year of Report 2010

FOOTNOTE DATA

Schedule Page: 203 Line No.: 24 Column: c

Account 234 - Accounts Payable to Associate Companies

Description	Balance at Beginning of Year	Balance at Close of Year
E.ON AG	$ 2,335,403	$ -
E.ON Sverige AB	7,343	-
PPL	-	2,998,747
LG&E and KU Energy LLC	1,715,279	5,116,810
LG&E Energy Marketing Inc.	41,094	511
Total	$ 4,099,119	$ 8,116,068

LG&E and KU Energy LLC was formerly E.ON U.S. LLC.

Schedule Page: 203 Line No.: 41 Column: c

Account 242 - Miscellaneous Current and Accrued Liabilities

Description	Balance at Beginning of Year	Balance at Close of Year
Accrued Officer Long Term Incentive (current portion)	$ 4,352,919	$ -
Accrued Short Term Incentive	2,848,763	3,395,927
Unclaimed Checks	650	-
Miscellaneous Liability - Vested Vacation	7,915,640	8,470,568
Pension Payable SERP Current	2,340,376	2,425,759
Retirement Income Liability	406,223	513,934
Total	$ 17,864,571	$ 14,806,188

1. Use the space below for important notes regarding the financial statements or any account thereof.
2. Furnish particulars as to any significant contingent assets or liabilities existing at the end of the year.
3. Furnish particulars as to any significant increase in services rendered or expenses incurred during the year.
4. Furnish particulars as to any amounts recorded in Account 434, Extraordinary Income, or Account 435, Extraordinary Deductions.
5. Notes relating to financial statements shown elsewhere in this report may be indicated here by reference.
6. Describe the annual statement supplied to each associate service company in support of the amount of interest on borrowed capital and compensation for use of capital billed during the calendar year. State the basis for billing of interest to each associate company. If a ratio, describe in detail how ratio is computed. If more than one ratio explain the calculation. Report the amount of interest borrowed and/or compensation for use of capital billed to each associate company.

Note 1 – Organization of LG&E and KU Services Company

LG&E and KU Services Company ("Servco" or the "Company") (formerly E.ON U.S. Services Inc.), a Kentucky corporation, is a wholly-owned subsidiary of LG&E and KU Energy LLC ("LKE") and a centralized service company under the Public Utility Holding Company Act of 2005 (PUHCA 2005). LKE, in turn, in a wholly-owned subsidiary of PPL Corporation ("PPL"). LKE became a wholly-owned subsidiary of PPL and Servco became an indirect, wholly-owned subsidiary of PPL when PPL acquired all the limited liability company interests of LKE from E.ON US Investments Corp. on November 1, 2010. On December 1, 2010, PPL and certain subsidiaries, including LKE, filed a notification of holding company status with the Federal Energy Regulatory Commission under PUHCA 2005. LKE had previously been party to such a notification filed on June 15, 2006 by E.ON AG, its former parent. Servco originally was authorized to conduct business as a service company for E.ON U.S. LLC (formerly LG&E Energy LLC) and its various subsidiaries and affiliates by order of the Securities and Exchange Commission dated December 6, 2000, and commenced operations January 1, 2001.

Servco provides certain services to affiliated entities, including LKE, PPL, LG&E and KU Capital LLC ("LKC"), LG&E Energy Marketing Inc. ("LEM"), Louisville Gas and Electric Company ("LG&E") and Kentucky Utilities Company ("KU"), at cost. Servco is organized along functional lines to accomplish its purpose of providing management, administrative, and technical services. These services are priced so that Servco operates on a break-even basis.

Note 2 - Summary of Significant Accounting Policies

Effective January 1, 2008, Servco transitioned to the Federal Energy Regulatory Commission Uniform System of Accounts for Centralized Service Companies Subject to the Provisions of PUHCA 2005. The accounting policies of Servco conform to U.S. generally accepted accounting principles ("GAAP").

Property. Property, plant and equipment includes property that is in use and under construction, and is reported at cost.

Depreciation and Amortization. Depreciation is computed on a straight-line basis. Office furniture is depreciated over 30 years and personal computers are depreciated over 3 years.

Income Taxes. 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. Accounting standards prescribe 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. Tax contingencies are analyzed periodically and adjustments are made when events occur to warrant a change. See also Note 8, Income Taxes, for additional tax information.

Accumulated 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. See Note 8, Income Taxes.

Management's Use of Estimates. The preparation of financial statements in conformity with GAAP requires management to make estimates and assumptions that affect the reported assets and liabilities, the disclosure of contingent liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. Actual results could differ from those estimates.

Recent Accounting Pronouncements.

Fair Value Measurements

In January 2010, the Financial Accounting Standards Board ("FASB") issued guidance related to fair value measurement disclosures requiring separate disclosure of amounts of significant transfers in and out of level 1 and level 2 fair value measurements and separate information about purchases, sales, issuances and settlements within level 3 measurements. This guidance is effective for the interim and annual reporting periods beginning after December 15, 2009, except for the disclosures about the roll-forward of activity in level 3 fair value measurements. Those disclosures are effective for fiscal years beginning after December 15, 2010 and for interim periods within those fiscal years. This guidance has no impact on the Company's results of operations, financial position, liquidity or disclosures.

Note 3 - Acquisition by PPL

On November 1, 2010, PPL completed its acquisition of LKE and its subsidiaries. The merger was accounted for using the purchase method of accounting in accordance with GAAP, and the applicable effects were "pushed down" or reflected on the financial statements of the subsidiaries as of the acquisition date. Accordingly, the financial statements were presented showing the predecessor and successor accounting periods. The accompanying financial statements, which do not present separate predecessor and successor accounting periods, were prepared in accordance with the accounting requirements set forth in the Uniform System of Accounts and published accounting releases of the Federal Energy Regulatory Commission, which is a comprehensive basis of accounting other than GAAP. The preparation of the financial statements in conformity with GAAP requires management to make periodic estimates and assumptions that affect the reported amounts of assets, liabilities, revenues and expenses during the reporting period.

The push-down basis of accounting was used to record the fair value adjustments of assets and liabilities on LKE and its subsidiaries at the acquisition date. The fair value of the consideration was paid by PPL to E.ON AG. Adjustments on November 1, 2010 were made to record property and pension assets at fair value, remeasure pension and postretirement benefit obligations at current discount rates and eliminate accumulated other comprehensive income (loss).

Note 4 - Fair Value Measurements

The Company adopted the fair value guidance in the FASB Accounting Standards Codification ("ASC") in two phases. Effective January 1, 2008, the Company adopted it for all financial instruments and non-financial instruments accounted for at fair value on a recurring basis and effective January 1, 2009, the Company adopted it for all non-financial instruments accounted for at fair value on a non-recurring basis. The FASB ASC guidance clarifies that fair value is an exit price, representing the amount that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants. As such, fair value is a market-based measurement that should be determined based on assumptions that market participants would use in pricing an asset or a liability. As a basis for considering such assumptions, the FASB ASC guidance establishes a three-tier value hierarchy, which prioritizes the inputs used in the valuation methodologies in measuring fair value.

The Company has classified the applicable financial assets and liabilities that are accounted for at fair value into the three levels of the fair value hierarchy, as discussed in Note 2, Summary of Significant Accounting Policies.

The following tables set forth, by level within the fair value hierarchy, the Company's financial assets and liabilities that were accounted for at fair value on a recurring basis.

(in millions)

December 31, 2010	Level 1	Level 2	Level 3	Total
Financial assets:				
Pension and postretirement plans	$ -	$ 185	$ -	$ 185

December 31, 2009	Level 1	Level 2	Level 3	Total
Financial assets:				
Pension and postretirement plans	$ -	$ 153	$ -	$ 153
Financial liabilities:				
E.ON share performance plan	$ -	$ 2	$ -	$ 2

See Note 3, Acquisition by PPL, for discussion of fair value of other assets and liabilities for purchase accounting.

Note 5 – Common Stock

Servco is authorized to issue 1,000 shares of common stock, no par value per share. At December 31, 2010, there were 1,000 shares authorized and 100 shares issued and outstanding. LG&E and KU Energy LLC holds all the Company's common stock.

Note 6 - Related Party Transactions

Provisions of Services

Servco engages in transactions in the normal course of business with other LKE subsidiaries. These transactions are primarily composed of services received and/or rendered.

Servco provides the subsidiaries of LKE with a variety of centralized administrative, management and support services. Charges for these services include labor and burdens of Servco employees performing services for the subsidiary of LKE and vouchers paid by Servco on behalf of the subsidiaries of LKE. The cost of these services is directly charged or, for general costs which cannot by directly attributed, charged based on predetermined allocation factors, including the ratios discussed in Methods of Allocations on pages 402.1 – 402.4.

Intercompany billings from Servco are listed on page 307, Analysis of Billing – Associate Companies (Account 457). These billings do not include convenience payments which are shown as a footnote to page 106, line 39, column b.

Note 7 - Pension and Other Postretirement Benefit Plans

Servco employees benefit from both funded and unfunded retirement benefit plans. Its defined benefit pension plans cover employees hired by December 31, 2005. Employees hired after this date participate in the Retirement Income Account ("RIA"), a defined contribution plan. The postretirement plan includes health care benefits that are contributory, with participants' contributions adjusted annually. The Company 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 defined benefit plans' obligations and fair value of assets for the two-year period ending December 31, 2010, and a statement of the funded status as of December 31:

(in millions)	Pension Benefits		Other Postretirement Benefits	
	2010	2009	2010	2009
Change in benefit obligation				
Benefit obligation at beginning of year	$305	$276	$24	$21
Service cost	10	10	2	1
Interest cost	19	17	1	1
Change due to transfers	1	1	-	-
Benefits paid, net of retiree contributions	(3)	(3)	(1)	-
Actuarial loss and other	38	4	1	1
Benefit obligation at end of year	$370	$305	$27	$24
Change in plan assets				
Fair value of plan assets at beginning of year	$140	$107	$13	$9
Actual return on plan assets	18	26	2	1
Employer contributions	11	10	5	3
Benefits paid, net of retiree contributions	(3)	(3)	(1)	-
Fair value of plan assets at end of year	$166	$140	$19	$ 13
Funded status at end of year	$(204)	$(165)	$(8)	$(11)

Amounts Recognized in the Balance Sheets

The following tables provide the amounts recognized in the Balance Sheet and information for plans with benefit obligations in excess of plan assets as of December 31:

(in millions)	Pension Benefits		Other Postretirement Benefits	
	2010	2009	2010	2009
Accrued benefit liability – current	$ (2)	$ (2)	$ -	$ -
Accrued benefit liability – non-current	(202)	(163)	(8)	(11)
Amounts recognized in accumulated OCI consist of:				
Transition obligation	$ -	$ -	$ -	$ -
Prior service cost	-	(23)	-	(1)
Accumulated gain (loss)	8	(78)	1	(4)
Total accumulated OCI	$ 8	$(101)	$ 1	$ (5)
Additional year-end information for plans with benefit obligations in excess of plan assets:				
Projected benefit obligation	$370	$305	$ 27	$ 24
Accumulated benefit obligation	272	221	-	-
Fair value of plan assets	166	140	19	13

The amounts recognized in accumulated other comprehensive income for the years ended December 31 are composed of the following:

(in millions)	Pension Benefits		Other Postretirement Benefits	
	2010	2009	2010	2009
Net loss (gain) arising during period	$ 37	$ (13)	$ 1	$ -
Amortization of prior service (cost) credit	(23)	(3)	(1)	-
Amortization of gain (loss)	(123)	(6)	(6)	-
Total amounts recognized in accumulated other comprehensive income	$(109)	$ (22)	$(6)	$ -

Components of Net Periodic Benefit Cost

These costs are assigned to various LKE subsidiaries based on the allocation factors outlined in the Cost Allocation Manual. The following table provides the components of net periodic benefit cost for the plans as of December 31:

	Pension Benefits		Other Postretirement Benefits	
(in millions)	2010	2009	2010	2009
Service cost	$ 10	$ 10	$ 2	$ 1
Interest cost	15	17	1	1
Expected return on plan assets	(11)	(10)	(1)	-
Amortization of prior service cost	3	3	-	-
Amortization of actuarial loss	4	6	-	-
Net periodic benefit cost	$21	$26	$ 2	$ 2

The estimated amounts that will be amortized from accumulated other comprehensive income into net periodic benefit cost in 2011 are zero.

The weighted average assumptions used in the measurement of Servco's pension benefit obligations as of December 31 are shown in the following table:

	2010	2009
Discount rate - non-union plan	5.52%	6.13%
Discount rate - SERP plan	5.11%	5.79%
Discount rate - officer SERP plan	5.46%	6.14%
Discount rate - restoration plan	5.66%	6.31%
Discount rate – postretirement plan	5.12%	5.82%
Rate of compensation increase	5.25%	5.25%

For the first ten months of 2010, the discount rates used to determine the pension and postretirement benefit obligations and the period expense were determined using the Mercer Pension Discount Yield Curve. This model takes the plans' cash flows and matches them to a yield curve that provides the equivalent yields on zero-coupon corporate bonds for each maturity. The discount rate is the single rate that produces the same present value of cash flows. The selection of the various discount rates represents the equivalent single rate under a broad-market AA yield curve constructed by Mercer.

For the last two months of 2010, the Towers Watson Yield Curve was used to determine the discount rate. This model starts with an analysis of the expected benefit payment stream for its plans. This information is first matched against a spot-rate yield curve. A portfolio of Aa-graded non-callable (or callable with make-whole provisions) bonds, with a total amount outstanding in excess of $667 billion, serves as the base from which those with the lowest and highest yields are eliminated to develop the ultimate yield curve. The results of this analysis are considered together with other economic data and movements in various bond indices to determine the discount rate assumption.

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

	2010	2009
Discount rate - pension	5.45%	6.25%
Discount rate - postretirement	4.94%	6.36%
Expected long-term rate of return on plan assets	7.25%	8.25%
Rate of compensation increase	5.25%	5.25%

To develop the expected long-term rate of return on assets assumption, Servco 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. The long-term rate of return on assets assumption was 7.75% for the first ten months of 2010 and 7.25% for the last two months. The Company has determined that the 2011 expected long-term rate of return on assets assumption should be 7.25%.

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

- A 1% change in the assumed discount rate would have a $34 million positive or negative impact to the 2010 accumulated benefit obligation and an approximate $52 million positive or negative impact to the 2010 projected benefit obligation.
- A 25 basis point change in the expected rate of return on assets would have less than $1 million positive or negative impact to 2010 pension expense.
- A 25 basis point increase in the rate of compensation increase would have a $6 million negative impact to the 2010 projected benefit obligation.

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 the first ten months of 2010. The rate was assumed to decrease gradually to 4.5% by 2029 and remain at that level thereafter. For the last two months of 2010, an 8% annual increase in the per capita cost of covered health care benefits was assumed and the rate was assumed to decrease gradually to 5.5% by 2019. For 2011, a 9% annual increase in the per capita cost of covered health care benefits is assumed and the rate is assumed to decrease gradually to 5.5% by 2019. This change in the length of the health care trend was made to conform to PPL's accounting policies.

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 to the 2010 total of service and interest costs components and year end 2010 postretirement benefit obligations.

Expected Future Benefit Payments

The following table provides the amount of expected future benefit payments, which reflect expected future service:

(in millions)	Pension Benefits	Other Postretirement Benefits
2011	$6	$1
2012	7	1
2013	8	1
2014	10	1
2015	12	2
2016 - 2020	96	12

Plan Assets

The following table shows Servco's weighted average asset allocations by asset category at for the Company's pension plans at December 31:

	Target Range	2010	2009
Equity securities	45%-75%	62%	59%
Debt securities	30%-50%	38%	40%
Other	0%-10%	0%	1%
Totals		100%	100%

The investment policy of the pension plans was developed in conjunction with financial and actuarial consultants, investment advisors and legal counsel. The goal of the investment policy is to preserve the capital of the pension plans' assets 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, Barclays Capital Aggregate and Barclays Capital 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 are either 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.

The Company has classified plan assets that are accounted for at fair value into the three levels of the fair value hierarchy, as defined by the fair value measurements and disclosures guidance of the FASB ASC. See Note 6, Fair Value Measurements, for further information.

A financial instrument's level within the fair value hierarchy is based on the lowest level of any input that is significant to the fair value measurement. Valuation techniques used need to maximize the use of observable inputs and minimize the use of unobservable inputs.

A description of the valuation methodologies used to measure plan assets at fair value is provided below:

> *Money Market Fund*: These investments are public investment vehicles valued using $1 for the net asset value. The money market funds are classified within level 2 of the valuation hierarchy.
>
> *Common/Collective Trusts:* Valued based on the beginning of year value of the plan's interests in the trust plus actual contributions and allocated investment income (loss) less actual distributions and allocated administrative expenses. Quoted market prices are used to value investments in the trust. The fair value of certain other investments for which quoted market prices are not available are valued based on yields currently available on comparable securities of issuers with similar credit ratings. The common/collective trusts are classified within level 2 of the valuation hierarchy.

The preceding methods described may produce a fair value that may not be indicative of net realizable value or reflective of future fair values. Furthermore, although the Company believes its valuation methods are appropriate and consistent with other plan market participants, the use of different methodologies or assumptions to determine the fair value of certain financial instruments could result in a different fair value measurement at the reporting date.

The following table sets forth, by level within the fair value hierarchy, the plans' assets at fair value as of December 31, 2010:

(in millions)	Level 2
Money Market Fund	$ 2
Common/Collective Trusts	183
Totals	$ 185

There are no assets categorized as level 1 or level 3.

Contributions

Servco made discretionary contributions to the pension plan of $9 million and $8 million in 2010 and 2009, respectively. Contributions to Supplemental Executive Retirement Plan ("SERP") payments totaled $2 million in each of 2010 and 2009. The Company funds its pension obligations in a manner consistent with the Pension Protection Act of 2006. In January 2011, the Company made a contribution to the pension plan of $38 million.

Servco made contributions to its other postretirement benefit plans of $5 million and $3 million in 2010 and 2009, respectively. In 2011, Servco plans on making voluntary contributions to fund VEBA 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. Servco's pension plan met the minimum funding requirements as defined by PPA for the years ended December 31, 2010 and 2009.

Thrift Savings Plan

Servco has a thrift savings plan under section 401(k) of the Internal Revenue Code. Under these plans, eligible employees may defer and contribute to the plans a portion of current compensation in order to provide future retirement benefits. The Company makes contributions to the plans by matching a portion of the employee's contributions. The costs of this matching were $4 million and $3 million in 2010 and 2009, respectively.

Servco 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. The Company 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 Servco under this arrangement equaled less than $1 million in both 2010 and 2009.

Health Care Reform

In March 2010, Health Care Reform (the Patient Protection and Affordable Care Act of 2010) was signed into law. Many provisions of Health Care Reform do not take effect for an extended period of time and many aspects of the law which are currently unclear or undefined will likely be clarified in future regulations.

Specific provisions within Health Care Reform that may impact Servco include:

- Beginning in 2011, requirements extend dependent coverage up to age 26, remove the $2 million lifetime maximum and eliminate cost sharing for certain preventative care procedures.
- Beginning in 2018, a potential excise tax is expected on high-cost plans providing health coverage that exceeds certain thresholds.

The Company has evaluated these provisions of Health Care Reform on its benefit programs in consultation with its actuarial consultants and has determined that the excise tax will not have an impact on its postretirement medical plans. The requirement to extend dependent coverage up to age 26 is not expected to have a significant impact on active or retiree medical costs. The Company will continue to monitor the potential impact of any changes to the existing provisions and implementation guidance related to Health Care Reform on its benefit programs.

Note 8 - Income Taxes

Servco's federal income tax return is included in a United States consolidated income tax return filed by Servco's direct parent. Prior to October 31, 2010, the return was included in the consolidated return of E.ON U.S. Investments Corp. Due to the acquisition by PPL, the return will be included in the consolidated PPL return beginning November 1, 2010, for each tax period. Each subsidiary of the consolidated tax group 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. The Company also files income tax returns in various state jurisdictions. While 2007 and later years are open under the federal statute of limitations, Revenue Agent Reports for 2007-2008 have been received from the IRS, effectively closing these years to additional audit adjustments. Tax years beginning with 2007 were examined under an IRS program, 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. The 2009 federal return was filed in the third quarter of 2010 and the IRS issued a Partial Acceptance Letter in connection with CAP. None of the remaining areas that the IRS is reviewing will impact Servco. The short tax year beginning January 1, 2010 through October 31, 2010, is also being examined under CAP. No material items have been raised by the IRS at this time. The two month period beginning November 1, 2010 and ending December 31, 2010 is not currently under examination.

Components of income tax expense are shown in the table below for the year ended December 31:

(in millions)	2010	2009
Current – federal	$ (5)	$ 2
Current – state	1	-
Deferred – federal – net	5	(2)
Deferred – state – net	(1)	-
Total income tax expense	$ -	$ -

Deferred tax assets and liabilities which are mainly of a long-term nature are summarized below as of December 31:

(in millions)	2010	2009
Deferred tax assets:		
Pensions and similar obligations	$82	$74
Liabilities and other	(3)	-
Net deferred income tax asset (current and noncurrent)	$79	$74
Balance sheet classification:		
ccassets:		
Current	$ 3	$ 2
Non current	76	72
Net deferred income tax asset (current and noncurrent)	$79	$74

Note 9 - Accumulated Other Comprehensive Income (Loss)

Accumulated other comprehensive income consisted of the following:

	Funded Status of Pension and Postretirement Plans		
	Pretax	Tax	Net
(in millions)			
Balance at December 31, 2008	$(128)	$ 50	$(78)
Change in funded status of pension and postretirement plans	22	(9)	13
Balance at December 31, 2009	$(106)	$41	$(65)
Change in funded status of pension and postretirement plans - pre-acquisition	(31)	12	(19)
Effect of PPL acquisition	137	(53)	84
Change in funded status of pension and postretirement plans - post-acquisition	9	(4)	5
Balance at December 31, 2010	$ 9	$ (4)	$ 5

Note 10 - Share Performance Plan

In 2006, the Company introduced a stock-based compensation system, the E.ON Share Performance Plan, and virtual shares were granted under the Plan to certain executives of the Company. The Plan was a stock-based compensation plan based on the value of E.ON's shares, and it entitled each participant to receive a payment at the end of a three-year and four-year vesting period equal to a target value per share times the number of virtual shares granted.

The number of virtual shares did not change during the three-year and four-year vesting periods, but the target value per share could change based on E.ON's stock price and the performance of E.ON stock during the three-year and four-year periods compared to the change in the Dow Jones STOXX Utilities Index (Total Return EUR). The Company used the fair-value method to account for the Plan. See Note 4, Fair Value Measurements, for further information.

The 2007 grant under E.ON Share Performance Plan of 6,820 virtual shares with target prices of €96.52 each was paid out in January 2010. The total of the payouts was less than $1 million. In the second quarter of 2010, the Company issued 27,643 virtual shares to Plan participants with a target price of €27.25.

All virtual shares vested on October 31, 2010, with the closing of the PPL acquisition. All shares were paid out in November 2010; the total of the payout was less than $1 million.

The Company recorded expense of less than $1 million related to the Plan in the year ended October 31, 2010 and less than $1 million in 2009.

Starting November 1, 2010, certain compensation of selected employees is provided by PPL, the expense related to this compensation was less than $1 million for 2010.

Note 11 - Subsequent Events

Subsequent events have been evaluated through April 29, 2011, the date of issuance of these statements. These statements contain all necessary adjustments and disclosures resulting from that evaluation.

On January 14, 2011, Servco contributed $38 million to its pension plans.

Name of Respondent	This Report Is:	Resubmission Date (Mo, Da, Yr)	Year/Period of Report
LG&E and KU Services Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	Dec 31, 2010

Schedule XV- Comparative Income Statement

Line No.	Account Number (a)	Title of Account (b)	Current Year (c)	Prior Year (d)
1		SERVICE COMPANY OPERATING REVENUES		
2	400	Service Company Operating Revenues	326,982,028	294,976,508
3		SERVICE COMPANY OPERATING EXPENSES		
4	401	Operation Expenses	185,458,788	185,159,920
5	402	Maintenance Expenses	25,622,139	23,864,256
6	403	Depreciation Expenses	467,896	625,801
7	403.1	Depreciation Expense for Asset Retirement Costs		
8	404	Amortization of Limited-Term Property		
9	405	Amortization of Other Property		
10	407.3	Regulatory Debits		
11	407.4	Regulatory Credits		
12	408.1	Taxes Other Than Income Taxes, Operating Income	7,851,795	6,976,260
13	409.1	Income Taxes, Operating Income	(4,270,130)	2,952,773
14	410.1	Provision for Deferred Income Taxes, Operating Income	27,518,247	7,588,963
15	411.1	Provision for Deferred Income Taxes – Credit, Operating Income	(23,198,547)	(10,541,736)
16	411.4	Investment Tax Credit, Service Company Property		
17	411.6	Gains from Disposition of Service Company Plant		
18	411.7	Losses from Disposition of Service Company Plant		
19	411.10	Accretion Expense		
20	412	Costs and Expenses of Construction or Other Services	84,274,390	59,950,618
21	416	Costs and Expenses of Merchandising, Jobbing, and Contract Work		
22		TOTAL SERVICE COMPANY OPERATING EXPENSES (Total of Lines 4-21)	303,724,578	276,576,855
23		NET SERVICE COMPANY OPERATING INCOME (Total of Lines 2 less 22)	23,257,450	18,399,653
24		OTHER INCOME		
25	418.1	Equity in Earnings of Subsidiary Companies		
26	419	Interest and Dividend Income	127,427	
27	419.1	Allowance for Other Funds Used During Construction		
28	421	Miscellaneous Income or Loss		
29	421.1	Gain on Disposition of Property		
30		TOTAL OTHER INCOME (Total of Lines 25-29)	127,427	
31		OTHER INCOME DEDUCTIONS		
32	421.2	Loss on Disposition of Property		
33	425	Miscellaneous Amortization		
34	426.1	Donations	2,673,140	1,552,178
35	426.2	Life Insurance		
36	426.3	Penalties	(161)	567
37	426.4	Expenditures for Certain Civic, Political and Related Activities	2,463,531	2,402,526
38	426.5	Other Deductions	18,168,109	14,444,232
39		TOTAL OTHER INCOME DEDUCTIONS (Total of Lines 32-38)	23,304,619	18,399,503

Name of Respondent LG&E and KU Services Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Resubmission Date (Mo, Da, Yr) / /	Year/Period of Report Dec 31, 2010

Schedule XV- Comparative Income Statement (continued)

Line No.	Account Number (a)	Title of Account (b)	Current Year (c)	Prior Year (d)
40		TAXES APPLICABLE TO OTHER INCOME AND DEDUCTIONS		
41	408.2	Taxes Other Than Income Taxes, Other Income and Deductions	2,400	150
42	409.2	Income Taxes, Other Income and Deductions		
43	410.2	Provision for Deferred Income Taxes, Other Income and Deductions		
44	411.2	Provision for Deferred Income Taxes – Credit, Other Income and Deductions		
45	411.5	Investment Tax Credit, Other Income Deductions		
46		TOTAL TAXES APPLICABLE TO OTHER INCOME AND DEDUCTIONS (Total of Lines 41-45)	2,400	150
47		INTEREST CHARGES		
48	427	Interest on Long-Term Debt		
49	428	Amortization of Debt Discount and Expense		
50	429	(less) Amortization of Premium on Debt- Credit		
51	430	Interest on Debt to Associate Companies		
52	431	Other Interest Expense		
53	432	(less) Allowance for Borrowed Funds Used During Construction-Credit		
54		TOTAL INTEREST CHARGES (Total of Lines 48-53)		
55		NET INCOME BEFORE EXTRAORDINARY ITEMS (Total of Lines 23, 30, minus 39, 46, and 54)	77,858	
56		EXTRAORDINARY ITEMS		
57	434	Extraordinary Income		
58	435	(less) Extraordinary Deductions		
59		Net Extraordinary Items (Line 57 less Line 58)		
60	409.4	(less) Income Taxes, Extraordinary		
61		Extraordinary Items After Taxes (Line 59 less Line 60)		
62		NET INCOME OR LOSS/COST OF SERVICE (Total of Lines 55-61)	77,858	

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Interest earned on note receivable from LG&E and KU Energy LLC.

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Schedule XVI- Analysis of Charges for Service- Associate and Non-Associate Companies

1. Total cost of service will equal for associate and nonassociate companies the total amount billed under their separate analysis of billing schedules.

Line No.	Account Number (a)	Title of Account (b)	Associate Company Direct Cost (c)	Associate Company Indirect Cost (d)	Associate Company Total Cost (e)	Nonassociate Company Direct Cost (f)	Nonassociate Company Indirect Cost (g)	Nonassociate Company Total Cost (h)
1	403-403.1	Depreciation Expense	467,896		467,896			
2	404-405	Amortization Expense						
3	407.3-407.4	Regulatory Debits/Credits – Net						
4	408.1-408.2	Taxes Other Than Income Taxes	1,710,488	6,143,707	7,854,195			
5	409.1-409.3	Income Taxes	(4,270,130)		(4,270,130)			
6	410.1-411.2	Provision for Deferred Taxes	27,518,247		27,518,247			
7	411.1-411.2	Provision for Deferred Taxes -- Credit	23,198,547		23,198,547			
8	411.6	Gain from Disposition of Service Company Plant						
9	411.7	Losses from Disposition of Service Company Plant						
10	411.4-411.5	Investment Tax Credit Adjustment						
11	411.10	Accretion Expense						
12	412	Costs and Expenses of Construction or Other Services	84,274,390		84,274,390			
13	416	Costs and Expenses of Merchandising, Jobbing, and Contract Work for Associated Companies						
14	418	Non-operating Rental Income						
15	418.1	Equity in Earnings of Subsidiary Companies						
16	419	Interest and Dividend Income	127,427		127,427			
17	419.1	Allowance for Other Funds Used During Construction						
18	421	Miscellaneous Income or Loss						
19	421.1	Gain on Disposition of Property						
20	421.2	Loss on Disposition Of Property						
21	425	Miscellaneous Amortization						
22	426.1	Donations	2,624,064	49,076	2,673,140			
23	426.2	Life Insurance						
24	426.3	Penalties	(161)		(161)			
25	426.4	Expenditures for Certain Civic, Political and Related Activities	376,093	2,087,438	2,463,531			
26	426.5	Other Deductions	17,872,461	295,648	18,168,109			
27	427	Interest On Long-Term Debt						
28	428	Amortization of Debt Discount and Expense						
29	429	Amortization of Premium on Debt -- Credit						
30	430	Interest on Debt to Associate Companies						
31	431	Other Interest Expense						
32	432	Allowance for Borrowed Funds Used During Construction						
33	500-509	Total Steam Power Generation Operation Expenses	(17,855,941)	5,754,878	(12,101,063)			
34	510-515	Total Steam Power Generation Maintenance Expenses	2,002,327	222,229	2,224,556			

Name of Respondent	This Report Is:	Resubmission Date (Mo, Da, Yr)	Year/Period of Report
LG&E and KU Services Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	Dec 31, 2010

Schedule XVI- Analysis of Charges for Service- Associate and Non-Associate Companies (continued)

Line No.	Account Number (a)	Title of Account (b)	Total Charges for Services Direct Cost (i)	Total Charges for Services Indirect Cost (j)	Total Charges for Services Total Cost (k)
1	403-403.1	Depreciation Expense	467,896		467,896
2	404-405	Amortization Expense			
3	407.3-407.4	Regulatory Debits/Credits – Net			
4	408.1-408.2	Taxes Other Than Income Taxes	1,710,488	6,143,707	7,854,195
5	409.1-409.3	Income Taxes	(4,270,130)		(4,270,130)
6	410.1-411.2	Provision for Deferred Taxes	27,518,247		27,518,247
7	411.1-411.2	Provision for Deferred Taxes – Credit	23,198,547		23,198,547
8	411.6	Gain from Disposition of Service Company Plant			
9	411.7	Losses from Disposition of Service Company Plant			
10	411.4-411.5	Investment Tax Credit Adjustment			
11	411.10	Accretion Expense			
12	412	Costs and Expenses of Construction or Other Services	84,274,390		84,274,390
13	416	Costs and Expenses of Merchandising, Jobbing, and Contract Work for Associated Companies			
14	418	Non-operating Rental Income			
15	418.1	Equity in Earnings of Subsidiary Companies			
16	419	Interest and Dividend Income	127,427		127,427
17	419.1	Allowance for Other Funds Used During Construction			
18	421	Miscellaneous Income or Loss			
19	421.1	Gain on Disposition of Property			
20	421.2	Loss on Disposition Of Property			
21	425	Miscellaneous Amortization			
22	426.1	Donations	2,624,064	49,076	2,673,140
23	426.2	Life Insurance			
24	426.3	Penalties	(161)		(161)
25	426.4	Expenditures for Certain Civic, Political and Related Activities	376,093	2,087,438	2,463,531
26	426.5	Other Deductions	17,872,461	295,648	18,168,109
27	427	Interest On Long-Term Debt			
28	428	Amortization of Debt Discount and Expense			
29	429	Amortization of Premium on Debt – Credit			
30	430	Interest on Debt to Associate Companies			
31	431	Other Interest Expense			
32	432	Allowance for Borrowed Funds Used During Construction			
33	500-509	Total Steam Power Generation Operation Expenses	(17,855,941)	5,754,878	(12,101,063)
34	510-515	Total Steam Power Generation Maintenance Expenses	2,002,327	222,229	2,224,556

Name of Respondent LG&E and KU Services Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Resubmission Date (Mo, Da, Yr) / /	Year/Period of Report Dec 31, 2010

Line No.	Account Number (a)	Title of Account (b)	Associate Company Direct Cost (c)	Associate Company Indirect Cost (d)	Associate Company Total Cost (e)	Nonassociate Company Direct Cost (f)	Nonassociate Company Indirect Cost (g)	Nonassociate Company Total Cost (h)
35	517-525	Total Nuclear Power Generation Operation Expenses						
36	528-532	Total Nuclear Power Generation Maintenance Expenses						
37	535-540.1	Total Hydraulic Power Generation Operation Expenses	2,001		2,001			
38	541-545.1	Total Hydraulic Power Generation Maintenance Expenses	5,824		5,824			
39	546-550.1	Total Other Power Generation Operation Expenses	11,311		11,311			
40	551-554.1	Total Other Power Generation Maintenance Expenses	125,843		125,843			
41	555-557	Total Other Power Supply Operation Expenses	87,041	3,476,354	3,563,395			
42	560	Operation Supervision and Engineering	61,065	1,815,520	1,876,585			
43	561.1	Load Dispatch-Reliability	92,784	2,380,008	2,472,792			
44	561.2	Load Dispatch-Monitor and Operate Transmission System						
45	561.3	Load Dispatch-Transmission Service and Scheduling						
46	561.4	Scheduling, System Control and Dispatch Services						
47	561.5	Reliability Planning and Standards Development		1,102,077	1,102,077			
48	561.6	Transmission Service Studies	21,824		21,824			
49	561.7	Generation Interconnection Studies						
50	561.8	Reliability Planning and Standards Development Services						
51	562	Station Expenses (Major Only)	35,176		35,176			
52	563	Overhead Line Expenses (Major Only)	111,590	20,376	131,966			
53	564	Underground Line Expenses (Major Only)						
54	565	Transmission of Electricity by Others (Major Only)						
55	566	Miscellaneous Transmission Expenses (Major Only)	1,442,201	2,445,623	3,887,824			
56	567	Rents						
57	567.1	Operation Supplies and Expenses (Nonmajor Only)						
58		Total Transmission Operation Expenses	1,764,640	7,763,604	9,528,244			
59	568	Maintenance Supervision and Engineering (Major Only)						
60	569	Maintenance of Structures (Major Only)						
61	569.1	Maintenance of Computer Hardware						
62	569.2	Maintenance of Computer Software						
63	569.3	Maintenance of Communication Equipment						
64	569.4	Maintenance of Miscellaneous Regional Transmission Plant						
65	570	Maintenance of Station Equipment (Major Only)	481,729		481,729			
66	571	Maintenance of Overhead Lines (Major Only)	253,467		253,467			
67	572	Maintenance of Underground Lines (Major Only)						
68	573	Maintenance of Miscellaneous Transmission Plant (Major Only)	38,396		38,396			

Name of Respondent	This Report Is:	Resubmission Date (Mo, Da, Yr)	Year/Period of Report
LG&E and KU Services Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	Dec 31, 2010

Schedule XVI- Analysis of Charges for Service- Associate and Non-Associate Companies (continued)

Line No.	Account Number (a)	Title of Account (b)	Total Charges for Services Direct Cost (i)	Total Charges for Services Indirect Cost (j)	Total Charges for Services Total Cost (k)
35	517-525	Total Nuclear Power Generation Operation Expenses			
36	528-532	Total Nuclear Power Generation Maintenance Expenses			
37	535-540.1	Total Hydraulic Power Generation Operation Expenses	2,001		2,001
38	541-545.1	Total Hydraulic Power Generation Maintenance Expenses	5,824		5,824
39	546-550.1	Total Other Power Generation Operation Expenses	11,311		11,311
40	551-554.1	Total Other Power Generation Maintenance Expenses	125,843		125,843
41	555-557	Total Other Power Supply Operation Expenses	87,041	3,476,354	3,563,395
42	560	Operation Supervision and Engineering	61,065	1,815,520	1,876,585
43	561.1	Load Dispatch-Reliability	92,784	2,380,008	2,472,792
44	561.2	Load Dispatch-Monitor and Operate Transmission System			
45	561.3	Load Dispatch-Transmission Service and Scheduling			
46	561.4	Scheduling, System Control and Dispatch Services			
47	561.5	Reliability Planning and Standards Development		1,102,077	1,102,077
48	561.6	Transmission Service Studies	21,824		21,824
49	561.7	Generation Interconnection Studies			
50	561.8	Reliability Planning and Standards Development Services			
51	562	Station Expenses (Major Only)	35,176		35,176
52	563	Overhead Line Expenses (Major Only)	111,590	20,376	131,966
53	564	Underground Line Expenses (Major Only)			
54	565	Transmission of Electricity by Others (Major Only)			
55	566	Miscellaneous Transmission Expenses (Major Only)	1,442,201	2,445,623	3,887,824
56	567	Rents			
57	567.1	Operation Supplies and Expenses (Nonmajor Only)			
58		Total Transmission Operation Expenses	1,764,640	7,763,604	9,528,244
59	568	Maintenance Supervision and Engineering (Major Only)			
60	569	Maintenance of Structures (Major Only)			
61	569.1	Maintenance of Computer Hardware			
62	569.2	Maintenance of Computer Software			
63	569.3	Maintenance of Communication Equipment			
64	569.4	Maintenance of Miscellaneous Regional Transmission Plant			
65	570	Maintenance of Station Equipment (Major Only)	481,729		481,729
66	571	Maintenance of Overhead Lines (Major Only)	253,467		253,467
67	572	Maintenance of Underground Lines (Major Only)			
68	573	Maintenance of Miscellaneous Transmission Plant (Major Only)	38,396		38,396

Name of Respondent	This Report Is:	Resubmission Date (Mo, Da, Yr)	Year/Period of Report
LG&E and KU Services Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	Dec 31, 2010

Line No.	Account Number (a)	Title of Account (b)	Associate Company Direct Cost (c)	Associate Company Indirect Cost (d)	Associate Company Total Cost (e)	Nonassociate Company Direct Cost (f)	Nonassociate Company Indirect Cost (g)	Nonassociate Company Total Cost (h)
69	574	Maintenance of Transmission Plant (Nonmajor Only)						
70		Total Transmission Maintenance Expenses	773,592		773,592			
71	575.1-575.8	Total Regional Market Operation Expenses						
72	576.1-576.5	Total Regional Market Maintenance Expenses						
73	580-589	Total Distribution Operation Expenses	4,790,727	2,233,681	7,024,408			
74	590-598	Total Distribution Maintenance Expenses	460,320		460,320			
75		Total Electric Operation and Maintenance Expenses	99,415,059	28,026,615	127,441,674			
76	700-798	Production Expenses (Provide selected accounts in a footnote)						
77	800-813	Total Other Gas Supply Operation Expenses	71,468		71,468			
78	814-826	Total Underground Storage Operation Expenses	6,870		6,870			
79	830-837	Total Underground Storage Maintenance Expenses	3,611		3,611			
80	840-842.3	Total Other Storage Operation Expenses						
81	843.1-843.9	Total Other Storage Maintenance Expenses						
82	844.1-846.2	Total Liquefied Natural Gas Terminaling and Processing Operation Expenses						
83	847.1-847.8	Total Liquefied Natural Gas Terminaling and Processing Maintenance Expenses						
84	850	Operation Supervision and Engineering						
85	851	System Control and Load Dispatching.						
86	852	Communication System Expenses						
87	853	Compressor Station Labor and Expenses						
88	854	Gas for Compressor Station Fuel						
89	855	Other Fuel and Power for Compressor Stations						
90	856	Mains Expenses	2,035		2,035			
91	857	Measuring and Regulating Station Expenses						
92	858	Transmission and Compression of Gas By Others						
93	859	Other Expenses						
94	860	Rents						
95		Total Gas Transmission Operation Expenses	2,035		2,035			
96	861	Maintenance Supervision and Engineering						
97	862	Maintenance of Structures and Improvements						
98	863	Maintenance of Mains	1,187		1,187			
99	864	Maintenance of Compressor Station Equipment						
100	865	Maintenance of Measuring And Regulating Station Equipment						
101	866	Maintenance of Communication Equipment						
102	867	Maintenance of Other Equipment						
103		Total Gas Transmission Maintenance Expenses	1,187		1,187			
104	870-881	Total Distribution Operation Expenses	1,049,029	117,283	1,166,312			

Name of Respondent	This Report Is:	Resubmission Date (Mo, Da, Yr)	Year/Period of Report
LG&E and KU Services Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	Dec 31, 2010

Schedule XVI- Analysis of Charges for Service- Associate and Non-Associate Companies (continued)

Line No.	Account Number (a)	Title of Account (b)	Total Charges for Services Direct Cost (i)	Total Charges for Services Indirect Cost (j)	Total Charges for Services Total Cost (k)
69	574	Maintenance of Transmission Plant (Nonmajor Only)			
70		Total Transmission Maintenance Expenses	773,592		773,592
71	575.1-575.8	Total Regional Market Operation Expenses			
72	576.1-576.5	Total Regional Market Maintenance Expenses			
73	580-589	Total Distribution Operation Expenses	4,790,727	2,233,681	7,024,408
74	590-598	Total Distribution Maintenance Expenses	460,320		460,320
75		Total Electric Operation and Maintenance Expenses	99,415,059	28,026,615	127,441,674
76	700-798	Production Expenses (Provide selected accounts in a footnote)			
77	800-813	Total Other Gas Supply Operation Expenses	71,468		71,468
78	814-826	Total Underground Storage Operation Expenses	6,870		6,870
79	830-837	Total Underground Storage Maintenance Expenses	3,611		3,611
80	840-842.3	Total Other Storage Operation Expenses			
81	843.1-843.9	Total Other Storage Maintenance Expenses			
82	844.1-846.2	Total Liquefied Natural Gas Terminaling and Processing Operation Expenses			
83	847.1-847.8	Total Liquefied Natural Gas Terminaling and Processing Maintenance Expenses			
84	850	Operation Supervision and Engineering			
85	851	System Control and Load Dispatching.			
86	852	Communication System Expenses			
87	853	Compressor Station Labor and Expenses			
88	854	Gas for Compressor Station Fuel			
89	855	Other Fuel and Power for Compressor Stations			
90	856	Mains Expenses	2,035		2,035
91	857	Measuring and Regulating Station Expenses			
92	858	Transmission and Compression of Gas By Others			
93	859	Other Expenses			
94	860	Rents			
95		Total Gas Transmission Operation Expenses	2,035		2,035
96	861	Maintenance Supervision and Engineering			
97	862	Maintenance of Structures and Improvements			
98	863	Maintenance of Mains	1,187		1,187
99	864	Maintenance of Compressor Station Equipment			
100	865	Maintenance of Measuring And Regulating Station Equipment			
101	866	Maintenance of Communication Equipment			
102	867	Maintenance of Other Equipment			
103		Total Gas Transmission Maintenance Expenses	1,187		1,187
104	870-881	Total Distribution Operation Expenses	1,049,029	117,283	1,166,312

Name of Respondent	This Report Is:	Resubmission Date (Mo, Da, Yr)	Year/Period of Report
LG&E and KU Services Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	Dec 31, 2010

Line No.	Account Number (a)	Title of Account (b)	Associate Company Direct Cost (c)	Associate Company Indirect Cost (d)	Associate Company Total Cost (e)	Nonassociate Company Direct Cost (f)	Nonassociate Company Indirect Cost (g)	Nonassociate Company Total Cost (h)
105	885-894	Total Distribution Maintenance Expenses	77,306		77,306			
106		Total Natural Gas Operation and Maintenance Expenses	1,211,506	117,283	1,328,789			
107	901	Supervision	3,043,007	655,130	3,698,137			
108	902	Meter reading expenses	125,044	108	125,152			
109	903	Customer records and collection expenses	6,950,380	8,445,233	15,395,613			
110	904	Uncollectible accounts						
111	905	Miscellaneous customer accounts expenses	862,902		862,902			
112	906	Total Customer Accounts Operation Expenses	10,981,333	9,100,471	20,081,804			
113	907	Supervision	109,041	335,087	444,128			
114	908	Customer assistance expenses	22,203,543	992,633	23,196,176			
115	909	Informational And Instructional Advertising Expenses	249,943		249,943			
116	910	Miscellaneous Customer Service And Informational Expenses	122,548	650,201	772,749			
117		Total Service and Informational Operation Accounts	22,685,075	1,977,921	24,662,996			
118	911	Supervision						
119	912	Demonstrating and Selling Expenses						
120	913	Advertising Expenses	85,066		85,066			
121	916	Miscellaneous Sales Expenses						
122		Total Sales Operation Expenses	85,066		85,066			
123	920	Administrative and General Salaries	6,718,401	36,934,255	43,652,656			
124	921	Office Supplies and Expenses	4,650,383	9,481,112	14,131,495			
125	923	Outside Services Employed	9,667,064	5,342,645	15,009,709			
126	924	Property Insurance	894,197		894,197			
127	925	Injuries and Damages	707,217	30,343	737,560			
128	926	Employee Pensions and Benefits	26,497,593	22,642,417	49,140,010			
129	928	Regulatory Commission Expenses	52,277		52,277			
130	930.1	General Advertising Expenses	967,356	32,461	999,817			
131	930.2	Miscellaneous General Expenses	392,642	6,343,579	6,736,221			
132	931	Rents						
133		Total Administrative and General Operation Expenses	50,547,130	80,806,812	131,353,942			
134	935	Maintenance of Structures and Equipment	536,919	21,412,980	21,949,899			
135		Total Administrative and General Maintenance Expenses	84,835,523	113,298,184	198,133,707			
136		Total Cost of Service	185,462,088	141,442,082	326,904,170			

Name of Respondent	This Report Is:	Resubmission Date (Mo, Da, Yr)	Year/Period of Report
LG&E and KU Services Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	Dec 31, 2010

Schedule XVI- Analysis of Charges for Service- Associate and Non-Associate Companies (continued)

Line No.	Account Number (a)	Title of Account (b)	Total Charges for Services Direct Cost (i)	Total Charges for Services Indirect Cost (j)	Total Charges for Services Total Cost (k)
105	885-894	Total Distribution Maintenance Expenses	77,306		77,306
106		Total Natural Gas Operation and Maintenance Expenses	1,211,506	117,283	1,328,789
107	901	Supervision	3,043,007	655,130	3,698,137
108	902	Meter reading expenses	125,044	108	125,152
109	903	Customer records and collection expenses	6,950,380	8,445,233	15,395,613
110	904	Uncollectible accounts			
111	905	Miscellaneous customer accounts expenses	862,902		862,902
112	906	Total Customer Accounts Operation Expenses	10,981,333	9,100,471	20,081,804
113	907	Supervision	109,041	335,087	444,128
114	908	Customer assistance expenses	22,203,543	992,633	23,196,176
115	909	Informational And Instructional Advertising Expenses	249,943		249,943
116	910	Miscellaneous Customer Service And Informational Expenses	122,548	650,201	772,749
117		Total Service and Informational Operation Accounts	22,685,075	1,977,921	24,662,996
118	911	Supervision			
119	912	Demonstrating and Selling Expenses			
120	913	Advertising Expenses	85,066		85,066
121	916	Miscellaneous Sales Expenses			
122		Total Sales Operation Expenses	85,066		85,066
123	920	Administrative and General Salaries	6,718,401	36,934,255	43,652,656
124	921	Office Supplies and Expenses	4,650,383	9,481,112	14,131,495
125	923	Outside Services Employed	9,667,064	5,342,645	15,009,709
126	924	Property Insurance	894,197		894,197
127	925	Injuries and Damages	707,217	30,343	737,560
128	926	Employee Pensions and Benefits	26,497,593	22,642,417	49,140,010
129	928	Regulatory Commission Expenses	52,277		52,277
130	930 1	General Advertising Expenses	967,356	32,461	999,817
131	930 2	Miscellaneous General Expenses	392,642	6,343,579	6,736,221
132	931	Rents			
133		Total Administrative and General Operation Expenses	50,547,130	80,806,812	131,353,942
134	935	Maintenance of Structures and Equipment	536,919	21,412,980	21,949,899
135		Total Administrative and General Maintenance Expenses	84,835,523	113,298,184	198,133,707
136		Total Cost of Service	185,462,088	141,442,082	326,904,170

Name of Respondent	This Report Is:	Resubmission Date (Mo, Da, Yr)	Year/Period of Report
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Schedule XVII - Analysis of Billing – Associate Companies (Account 457)

1. For services rendered to associate companies (Account 457), list all of the associate companies.

Line No.	Name of Associate Company (a)	Account 457.1 Direct Costs Charged (b)	Account 457.2 Indirect Costs Charged (c)	Account 457.3 Compensation For Use of Capital (d)	Total Amount Billed (e)
1	LG&E and KU Capital LLC	35,324,673	6,981,737		42,306,410
2	LG&E and KU Energy LLC	166,930			166,930
3	LG&E Energy Inc.	800			800
4	LG&E Energy Marketing Inc.	1,574	5,078		6,652
5	LG&E International Inc.	29,746			29,746
6	Louisville Gas and Electric Company	65,788,910	62,449,141		128,238,051
7	Kentucky Utilities Company	82,921,020	72,014,456		154,935,476
8	Western Kentucky Energy Corp.	1,306,293	(8,330)		1,297,963
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40	Total	185,539,946	141,442,082		326,982,028

Name of Respondent	This Report Is:	Resubmission Date (Mo, Da, Yr)	Year/Period of Report
LG&E and KU Services Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	Dec 31, 2010

Schedule XVIII – Analysis of Billing – Non-Associate Companies (Account 458)

1. For services rendered to nonassociate companies (Account 458), list all of the nonassociate companies. In a footnote, describe the services rendered to each respective nonassociate company.

Line No.	Name of Non-associate Company (a)	Account 458.1 Direct Costs Charged (b)	Account 458.2 Indirect Costs Charged (c)	Account 458.3 Compensation For Use of Capital (d)	Account 458.4 Excess or Deficiency on Servicing Non-associate Utility Companies (e)	Total Amount Billed (f)
1	None					
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40	Total					

Name of Respondent	This Report Is:	Resubmission Date (Mo, Da, Yr)	Year/Period of Report
LG&E and KU Services Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	Dec 31, 2010

Schedule XIX - Miscellaneous General Expenses - Account 930.2

1. Provide a listing of the amount included in Account 930.2, "Miscellaneous General Expenses" classifying such expenses according to their nature. Amounts less than $50,000 may be grouped showing the number of items and the total for the group.
2. Payments and expenses permitted by Section 321 (b)(2) of the Federal Election Campaign Act, as amended by Public Law 94-283 in 1976 (2 U.S.C. 441(b)(2)) shall be separately classified.

Line No.	Title of Account (a)	Amount (b)
1	Association Dues - American Gas Association	296,869
2	Association Dues - Edison Electric Institute	812,241
3	Business License Fees	89,084
4	Other Miscellaneous General Expenses	2,672,770
5	Research and Development Expenses - Electric Power Research Institute	2,865,257
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40	Total	6,736,221

Schedule Page: 307 Line No.: 4 Column: a

Other Miscellaneous General Expenses includes $2,579,516 of indirect charges from PPL, $61,041 of third party labor for indirect research work and the remaining items are all under $50,000. Indirect charges from PPL include executive management, environmental management, external affairs, financial, legal, PPL Services, Inc. and risk management.

Name of Respondent	This Report is:	Resubmission Date (Mo, Da, Yr)	Year of Report
LG&E and KU Services Company	(1) X An Original (2) _ A Resubmission	/ /	2010

Schedule XX - Organization Chart

1. Provide a graphical presentation of the relationships and inter relationships within the service company that identifies lines of authority and responsibility in the organization.

The following were officers of Servco as of December 31, 2010:

Victor A. Staffieri -- Chairman of the Board, Chief Executive Officer and President

John R. McCall -- Executive Vice President, General Counsel, Corporate Secretary and Chief Compliance Officer
- Paula H. Pottinger -- Senior Vice President, Human Resources
- Michael S. Beer -- Vice President, Federal Regulation and Policy
- Lonnie E. Bellar -- Vice President, State Regulation and Rates
- Laura G. Douglas -- Vice President, Corporate Responsibility and Community Affairs
- R.W. "Chip" Keeling -- Vice President, Communications
- Dorothy E. O'Brien -- Vice President and Deputy General Counsel, Legal and Environmental Affairs
- George R. Siemens -- Vice President, External Affairs

S. Bradford Rives -- Chief Financial Officer
- Kent W. Blake -- Vice President, Corporate Planning and Development
- Daniel K. Arbough -- Treasurer
- Valerie L. Scott -- Controller
- Eric Slavinsky -- Chief Information Officer

Paul W. Thompson -- Senior Vice President, Energy Services
- D. Ralph Bowling -- Vice President, Power Production
- David S. Sinclair -- Vice President, Energy Marketing
- John N. Voyles, Jr. -- Vice President, Transmission and Generation Services

Chris Hermann -- Senior Vice President, Energy Delivery
- John P. Malloy -- Vice President, Energy Delivery, Retail Business
- P. Greg Thomas -- Vice President, Energy Delivery, Distribution Operations

Martyn Gallus* -- Senior Vice President - Energy Marketing

* Martyn Gallus resigned as Senior Vice President of Energy Marketing, effective January 3, 2011.

Name of Respondent	This Report is:	Resubmission Date (Mo, Da, Yr)	Year of Report
LG&E and KU Services Company	(1) X An Original (2) __ A Resubmission	/ /	2010

Schedule XXI - Methods of Allocation

1. Indicate the service department or function and the basis for allocation used when employees render services to more than one department or functional group. If a ratio, include the numerator and denominator.
2. Include any other allocation methods used to allocate costs.

Service Department or Function	Basis of Allocation
Customer Services	Number of Customers Ratio
Sales and Marketing Services	Departmental Charge Ratio
Economic Development and Major Account Services	Number of Customers Ratio
Meter Reading Services	Departmental Charge Ratio
Meter Operations Services	Number of Meters Ratio
Meter Asset Management Services	Number of Meters Ratio
Cash Remittance Services	Revenue Ratio
Billing Integrity Services	Number of Customers Ratio
Energy Efficiency Services	Number of Customers Ratio
CCS Retail Business Readiness	Number of Customers Ratio
Project Engineering Services	Total Assets Ratio
System Laboratory Services	Departmental Charge Ratio
Generation Services	Total Assets Ratio
Combustion Turbine Operations and Maintenance Services	Utility Ownership Percentages
Fuel Procurement Services	Contract Ratio
Transmission Strategy and Planning Services	Departmental Charge Ratio
Transmission Protection and Substation Services	Departmental Charge Ratio
Transmission Line Services	Departmental Charge Ratio
Transmission Reliability and Compliance Services	Departmental Charge Ratio
Transmission System Operations Services	Departmental Charge Ratio
Transmission EMS Services	Departmental Charge Ratio
Project Development Services	Departmental Charge Ratio
Energy Marketing Services	Generation Ratio
Market Forecasting Services	Generation Ratio
Load Forecasting Services	Generation Ratio
Generation Planning and Analysis Services	Electric Peak Load Ratio
Network Trouble and Dispatch Services	Departmental Charge Ratio
Mapping and Records Management Services	Departmental Charge Ratio
Electric Engineering Services	Departmental Charge Ratio
Distribution Asset Management Services	Total Assets Ratio
Substation Construction and Maintenance Services	Departmental Charge Ratio
Budgeting Services	Revenue, Total Assets and Number of Employees Ratios

Schedule XXI - Methods of Allocation

Financial Planning Services	Direct Expense Ratio
Financial Systems	Number of Employees Ratio
Strategic Planning Services	Departmental Charge Ratio
Internal Financial and Management Reporting Services	Departmental Charge Ratios
External Financial Reporting Services	Departmental Charge Ratios
Accounting and Reporting Services	Departmental Charge Ratios
Sundry Billings Services	Revenue, Total Assets and Number of Employees Ratios
Property Accounting Services	Total Assets Ratio
Energy Marketing Accounting Services	Energy Marketing Ratio
Revenue Accounting Services	Retail Revenue Ratio
Payroll Services	Number of Employees Ratio
Tax Accounting, Compliance and Reporting Services	Direct Expense Ratio
Tax Planning Services	Direct Expense Ratio
Tax Special Projects Services	Direct Charges Only
Audit Services	Project Ratio
Cash Management and Investment Services	Revenue, Total Assets, Number of Employees and Direct Expense Ratios
Corporate Finance Services	Direct Expense Ratio
Risk Management Services	Direct Expense Ratio
Credit Administration Services	Generation Ratio
Energy Marketing Trading Controls Services	Generation Ratio
Energy Marketing Contract Administration Services	Generation Ratio
Procurement and Major Contracts Services	Non-Fuel Material and Services Expenditures Ratio
Strategic Sourcing Services	Non-Fuel Material and Services Expenditures Ratio
Materials Logistics Services	Number of Transactions Ratio
Sourcing Support Services	Non-Fuel Material and Services Expenditures Ratio
Accounts Payable Services	Number of Transactions Ratio
Supplier Diversity	Non-Fuel Material and Services Expenditures Ratio
IT Corporate Functions Services	Number of Employees Ratio
IT Security and Administrative Services	Number of Employees Ratio
IT Enhancements	Number of Employees Ratio
IT Application Services	Number of Employees Ratio
IT Client Services	Number of Employees Ratio
IT Platform Services	Number of Employees Ratio
Legal Services	Departmental Charge Ratio
Compliance Services	Number of Employees Ratio
Environmental Affairs Services	Electric Peak Load Ratio
Regulatory Affairs Services	Revenue Ratio
Government Affairs Management Services	Departmental Charge Ratio

Internal Communication Services	Departmental Charge Ratio
External and Brand Communication Services	Departmental Charge Ratio
Public Affairs Management Services (Corp Responsibility)	Departmental Charge Ratio
Facilities and Building Services	Departmental Charge Ratio
Security Services	Departmental Charge Ratio
Production Mail Services	Number of Customers Ratio
Document Services	Number of Employees Ratio
Right-of-Way Services	Number of Customers Ratio
Transportation Services	Transportation Resource Management System Chargeback Rates
HR Compensation Services	Number of Employees Ratio
HR Benefits Services	Number of Employees Ratio
HR Health and Safety Services	Number of Employees Ratio
HR Organization Development and Training Services	Number of Employees Ratio
HR Services	Number of Employees Ratio
Technical and Safety Training Services	Number of Employees Ratio
Industrial Relations Management Services	Contract Ratio
Executive Management Services	Departmental Charge Ratio

Contract Ratio – Based on the sum of the physical amount (i.e. tons of coal, cubic feet of natural gas) of the contract for both coal and natural gas for the immediately preceding twelve consecutive calendar months, the numerator of which is for an operating company or an affected affiliate company and the denominator of which is for all operating companies and affected affiliate companies.

Departmental Charge Ratio – A specific Servco department ratio based upon various factors such as labor hours, labor dollars, departmental or entity headcount, etc. The departmental charge ratio typically applies to indirectly attributable costs such as departmental administrative, support, and/or material and supply costs that benefit more than one affiliate and that require allocation using general measures of cost causation. Methods for assignment are department-specific depending on the type of service being performed and are documented and monitored by the Budget Coordinators for each department.

Direct Expense Ratio – Based on the sum of the directly charged expenses at the end of each month for the immediately preceding twelve consecutive calendar months, the numerator of which is for an operating company or affected affiliate company and the denominator of which is for all operating companies and affected affiliate companies.

Electric Peak Load Ratio – Based on the sum of the monthly electric maximum system demands for the immediately preceding twelve consecutive calendar months, the numerator of which is for an operating company and the denominator of which is for all operating companies.

Energy Marketing Ratio – Based on the absolute value of megawatt hours purchased and sold for the immediately preceding twelve consecutive calendar months, the numerator of which is for an operating company or an affiliate and the denominator of which is for all operating companies and affected affiliate companies.

Generation Ratio – Based on the annual forecast of megawatt hours, the numerator of which is for an operating company or an affiliate and the denominator of which is for all operating companies and affected affiliate companies.

Non-Fuel Material and Services Expenditures – Based on non-fuel material and services expenditures, net of reimbursements, for the immediately preceding twelve consecutive calendar months. The numerator is equal to such expenditures for a specific entity and/or line-of-business as appropriate and the denominator is equal to such expenditures for all applicable entities.

Number of Customers Ratio – Based on the number of retail electric and/or gas customers. This ratio will be determined based on the actual number of customers at the end of the previous calendar year. In some cases, the ratio may be calculated based on the type of customer class being served (i.e. Residential, Commercial or Industrial).

Number of Employees Ratio – Based on the number of employees benefiting from the performance of a service. This ratio will be determined based on actual counts of applicable employees at the end of the previous calendar year. A two-step assignment methodology is utilized to properly allocate Servco employee costs to the proper legal entity.

Number of Meters Ratio – Based on the number or types of meters being utilized by all levels of customer classes within the system for the immediately preceding twelve consecutive calendar months. The numerator is equal to the number of meters for each utility and the denominator is equal to the total meters for KU and LG&E.

Number of Transactions Ratio – Based on the sum of transactions occurring in the immediately preceding twelve consecutive calendar months, the numerator of which is for an operating company or an affected affiliate company and the denominator of which is for all operating companies and affected affiliate companies. For example, services pertaining to Materials Logistics would define the transaction as the number of items ordered, picked and disbursed out of the warehouse. Services pertaining to Accounts Payable would define the transaction as the number of invoices processed. The Regulatory Accounting and Reporting Department is responsible for maintaining and monitoring specific service methodology documentation for actual transactions related to Servco billings.

Project Ratio – Based on the total costs for any departmental or affiliate project for the immediately preceding twelve consecutive calendar months, the numerator of which is for an operating company or an affected affiliate company and the denominator of which is for all operating companies and affected affiliate companies.

Retail Revenue Ratio – Based on utility revenues, excluding energy marketing revenues, for the immediately preceding twelve consecutive calendar months, the numerator of which is for an operating company or an affiliate and the denominator of which is for all operating companies and affected affiliate companies.

Revenue Ratio – Based on the sum of the revenue for the immediately preceding twelve consecutive calendar months, the numerator of which is for an operating company or an affected affiliate company and the denominator of which is for all operating companies and affected affiliate companies.

Total Assets Ratio – Based on the total assets at year end for the preceding year, the numerator of which is for an operating company or affected affiliate company and the denominator of which is for all operating companies and affected affiliate companies. In the event of joint ownership of a specific asset, asset ownership percentages are utilized to assign costs.

Transportation Resource Management System Chargeback Rate –Based on the costs associated with providing and operating transportation fleet for all affiliated companies including developing fleet policy, administering regulatory compliance programs, managing repair and maintenance of vehicles and procuring vehicles. Such rates are applied based on the specific equipment employment and the measured usage of services by the various company entities.

Utility Ownership Percentages – Based on the contractual ownership percentages of jointly-owned generating units.

Schedule of Professional Employees Transferred
2010

Name	NewCompany	OldCompany	New Job Title	Old Job Title	Eff Date
Henry,James D	E.ON U.S. Services Inc.	Louisville Gas & Electric Co.	Mgr Fleet Ops Perf & Reliab	Manager - Production	2010-02-08
Gerstle,Kelly Rae	E.ON U.S. Services Inc.	Louisville Gas & Electric Co.	Engy Efficiency Cust Srv Assoc	Sr Service Order Assoc	2010-02-15
Goodlett,Ramona Ann	E.ON U.S. Services Inc.	Louisville Gas & Electric Co.	Remittance Associate	Billing Analysis Assoc II	2010-02-22
McFarland,Elizabeth J	E.ON U.S. Services Inc.	Louisville Gas & Electric Co.	Mgr Subst Const & Maint	Lead Engineer	2010-03-01
Wolfe,John K	E.ON U.S. Services Inc.	Louisville Gas & Electric Co.	Dir Distribution Operations	Mgr Operations Center	2010-03-01
Wenz,William Charles	E.ON U.S. Services Inc.	Kentucky Utilities	Electric System Coordinator I	Unit Operator	2010-03-15
Mattingly,Cynthia Yates	E.ON U.S. Services Inc.	Kentucky Utilities	Retail Services Trainer	Sr Customer Representative	2010-04-11
Richerson,Bryan Keith	E.ON U.S. Services Inc.	Kentucky Utilities	Inspector - Transmission Lines	Line Technician A	2010-05-02
Tummonds,David L	E.ON U.S. Services Inc.	Kentucky Utilities	Mgr Generation Engineering	Experienced Engineeer	2010-05-03
Smith,Timothy P	E.ON U.S. Services Inc.	Kentucky Utilities	Mgr Commercial Operations	Mgr Commercial Operations	2010-07-12
Baker,Bryan D	LG&E and KU Services Company	Kentucky Utilities	Grp Ldr - Engineering	Supervisor - Maintenance	2010-11-29
Roper,Howard Allen	LG&E and KU Services Company	Kentucky Utilities	Inspector - Transmission Lines	Line Or Service Supervisor A	2010-12-13