COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

APPLICATION OF KENTUCKY UTILITIES	**)**	**CASE NO.**
COMPANY FOR AN ADJUSTMENT OF	**)**	**2014-00371**
ITS ELECTRIC RATES	**)**	

RESPONSE OF
KENTUCKY UTILITIES COMPANY
TO
THE SECOND SET OF DATA REQUESTS OF
KENTUCKY INDUSTRIAL UTILITY CUSTOMERS, INC.
DATED FEBRUARY 6, 2015

FILED: FEBRUARY 20, 2015

VERIFICATION

COMMONWEALTH OF KENTUCKY)
) SS:
COUNTY OF JEFFERSON)

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

Daniel K. Arbough

Daniel K. Arbough

Subscribed and sworn to before me, a Notary Public in and before said County and State, this 13th day of February 2015.

Judy Schooler (SEAL)

Notary Public

My Commission Expires:

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

VERIFICATION

COMMONWEALTH OF KENTUCKY)
) SS:
COUNTY OF JEFFERSON)

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

KtWBlake
Kent W. Blake

Subscribed and sworn to before me, a Notary Public in and before said County and State, this 18th day of February 2015.

Judy Schooler (SEAL)
Notary Public

My Commission Expires:

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

VERIFICATION

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

The undersigned, **Christopher M. Garrett**, being duly sworn, deposes and says that he is Director – Accounting and Regulatory Reporting for Kentucky Utilities Company and Louisville Gas and Electric Company and an employee of LG&E and KU Services Company, that he has personal knowledge of the matters set forth in the responses for which he is identified as the witness, and the answers contained therein are true and correct to the best of his information, knowledge and belief.

Christopher M. Garrett

Christopher M. Garrett

Subscribed and sworn to before me, a Notary Public in and before said County and State, this 13th day of February 2015.

Judy Schooler (SEAL)
Notary Public

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

VERIFICATION

COMMONWEALTH OF KENTUCKY)
) SS:
COUNTY OF JEFFERSON)

The undersigned, **Russel A. Hudson**, being duly sworn, deposes and says that he is Director – Financial Resource Management for Louisville Gas and Electric Company and Kentucky Utilities Company, an employee of LG&E and KU Services Company, and that he has personal knowledge of the matters set forth in the responses for which he is identified as the witness, and the answers contained therein are true and correct to the best of his information, knowledge and belief.

Russel A. Hudson
Russel A. Hudson

Subscribed and sworn to before me, a Notary Public in and before said County and State, this 18th day of February 2015.

Judy Schooler (SEAL)
Notary Public

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

VERIFICATION

COMMONWEALTH OF KENTUCKY)
) SS:
COUNTY OF JEFFERSON)

The undersigned, **Paula H. Pottinger, Ph.D.**, being duly sworn, deposes and says that she is Senior Vice President, Human Resources for Kentucky Utilities Company and Louisville Gas and Electric Company and an employee of LG&E and KU Services Company, and that she has personal knowledge of the matters set forth in the responses for which she is identified as the witness, and the answers contained therein are true and correct to the best of her information, knowledge and belief.

Paula H. Pottinger

Paula H. Pottinger, Ph.D.

Subscribed and sworn to before me, a Notary Public in and before said County and State, this 13th day of February 2015.

Judy Schooler (SEAL)
Notary Public

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

VERIFICATION

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

The undersigned, **Valerie L. Scott**, being duly sworn, deposes and says that she is Controller for Kentucky Utilities Company and Louisville Gas and Electric Company and an employee of LG&E and KU Services Company, and that she has personal knowledge of the matters set forth in the responses for which she is identified as the witness, and the answers contained therein are true and correct to the best of her information, knowledge and belief.

Valerie L. Scott
Valerie L. Scott

Subscribed and sworn to before me, a Notary Public in and before said County and State, this 19th day of February 2015.

Judy Schooler (SEAL)
Notary Public

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

VERIFICATION

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

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

John J. Spanos
JOHN J. SPANOS

Subscribed and sworn to before me, a Notary Public in and before said County and Commonwealth, this 12th day of February 2015.

__________________(SEAL)
Notary Public

My Commission Expires:
February 20, 2019

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

KENTUCKY UTILITIES COMPANY

CASE NO. 2014-00371

Response to Second Set of Data Requests of
Kentucky Industrial Utility Customers, Inc.
Dated February 6, 2015

Question No. 2-1

Responding Witness: Daniel K. Arbough

Q.2-1. The Companies presently use the RP-2000 scale AA mortality table to quantify pension and other post-retirement benefits expense. The Society of Actuaries issued the Mortality Improvement Scale 33 Report in September 2012 reflecting improved mortalities (longer lives). The Companies considered switching to the scale BB for year-end 2013, but apparently opted not to do so, according to the emails provided in response to KIUC 1-17 (page 25 of 101). Please explain why the Companies did not change to the scale BB once it became available for 2013 and 2014 pension and OPEB expense. In addition, please identify the person(s) and their positions who made this decision.

A.2-1. The Companies used the RP-2000 scale AA table to determine 2014 expense, but did not use it to determine the year-end 2014 liability. As noted in the response to Question Nos. 2-3 and 2-4, the adjusted RP-2014 table was used to determine the year-end pension and post-employment liabilities. The Companies did consider switching to the scale BB for year-end 2013, but demographic losses had not been significant and the Companies were aware of the planned release of the RP-2014 table. As discussed in more detail in the response to Question No. 2-3, Towers Watson completed a detailed demographic study in 2014 which provided support for the changes made at year-end 2014. The decision to use the scale AA table was made by a group of senior officers including the CFO.

KENTUCKY UTILITIES COMPANY

CASE NO. 2014-00371

Response to Second Set of Data Requests of
Kentucky Industrial Utility Customers, Inc.
Dated February 6, 2015

Question No. 2-2

Responding Witness: Daniel K. Arbough

Q.2-2. Is it the Company's position that it is required to adopt utilize the RP-2014 mortality table to quantify pension and OPEB expense starting in 2014? If so, please provide all support for this requirement.

A.2-2. No, KU did not take the position that it was required to adopt the RP-2014 mortality table to quantify pension and OPEB expense in 2014. KU utilized the RP-2000 mortality table to quantify pension and post-retirement benefit expense for 2014.

KENTUCKY UTILITIES COMPANY

CASE NO. 2014-00371

Response to Second Set of Data Requests of
Kentucky Industrial Utility Customers, Inc.
Dated February 6, 2015

Question No. 2-3

Responding Witness: Kent W. Blake / Daniel K. Arbough

Q.2-3. Is it the Company's position that it is required to adopt utilize the RP-2014 mortality table to quantify pension and OPEB expense starting in 2015? If so, please provide all support for this requirement. In addition, please provide all support for the proposition that the Company is required to utilize the RP-2014 mortality table starting in 2015, but not in 2014.

A.2-3. KU is required to issue financial statements that are compliant with GAAP. When measuring a plan's defined benefit obligation and recording the net periodic benefit cost, Accounting Standards Codification (ASC) 715-30-35-42 states that "each significant assumption used shall reflect the best estimate solely with respect to that individual assumption."

Based upon analyses and studies discussed below, KU determined that the RP-2014 mortality table as adjusted was the best estimate of actual experience available to calculate expense for 2015 and therefore should be utilized in order for the Company to be complaint with GAAP.

The Society of Actuaries (SOA) does not require the use of the RP-2014 tables; the SOA encourages all pension actuaries to carefully review the SOA report. The Actuarial Standards Board (ASB) promulgates actuarial standards of practice (ASOPs), which apply to U.S. actuaries. These standards require the actuary to consider the likelihood and extent of mortality improvements as a factor in setting the mortality assumptions and must consider the effect of mortality improvement. Actuaries have an obligation to recommend assumptions that will reflect the best estimate of liabilities, but these standards do not require the use of specific mortality tables.

The IRS dictates the mortality assumptions for pension funding, leaving plan sponsors limited flexibility in the assumptions they use for financial accounting purposes. The IRS is only required by statute to update the required mortality assumption once every 10 years. The fact that the IRS is not requiring use of the RP-2014 tables immediately did not affect KU's determination of its best estimate for the mortality assumption.

While the SEC is not requiring the use of the RP-2014 tables, it has shared the following information. On December 8, 2014, T. Kirk Crews, a Professional Accounting Fellow with the Office of the Chief Accountant of the U.S. Securities and Exchange Commission (SEC), spoke before the 2014 American Institute of Certified Public Accountants' National Conference on Current SEC and Public Company Accounting Oversight Board (PCAOB) Developments. In this speech, he stated that "given plan sponsors have historically utilized the SOA's mortality data and that data has been updated, the [SEC] staff does not believe it would be appropriate for a registrant to disregard the SOA's new mortality data in determining their best estimate of mortality."

Ernst & Young, KU's auditor, issued a briefing on October 30, 2014 which stated, "While the use of the SOA tables is not required, the SOA is a leading authority on actuarial research, and a large number of plan sponsors use its mortality tables and mortality improvement scale as a starting point or basis to develop their mortality assumptions. … Many sponsors that currently use the SOA's older mortality tables and scales are expected to use the new tables and scale, unless they have "credible" information supporting the use of a different table and scale." See Attachment #1 for the full Ernst & Young briefing.

Another large independent accounting firm, Deloitte, stated that in measuring each plan's defined benefit obligation and recording the net periodic benefit cost, "[E]ach significant assumption used shall reflect the best estimate solely with respect to that individual assumption. … In selecting the year-end mortality assumption, entities should (1) carefully evaluate the [SOA Retirement Plans Experience Committee] RPEC's report, (2) obtain an understanding of the new RP-2014 mortality tables and MP-2014 improvement scale, and (3) consider the relevance of the data underlying such tables and improvement scale to the specific population cover by their defined benefit plans." See Attachment #2 for the full Deloitte Financial Reporting Alert.

In February 2015, the American Institute for Certified Public Accountants (AICPA) issued a Technical Questions and Answers bulletin that stated "[S]ponsoring entities should consider the specific requirements of generally accepted accounting principles (GAAP), which require the use of a mortality assumption that reflects the best estimate of the plan's future experience for purposes of estimating the plan's obligation as of the current measurement date (that is, the date at which the obligation is presented in the financial statements). In making this estimate, GAAP requires that all available information through the date the financial statements are available to be issued should be evaluated to determine if the information provides additional evidence about conditions that existed at the balance sheet date. FASB Accounting Standards Codification

(ASC) 855-10-55-1 specifies that information that becomes available after the balance sheet date (but before the financial statements are available to be issued) may be indicative of conditions existing at the balance sheet date when that information is a culmination of conditions that existed over a long period of time. Updated mortality tables are based on historical trends and data that go back many years; therefore, the existence of updated mortality conditions is not predicated upon the date that the updated mortality tables are published." See Attachment #3 for the full AICPA bulletin.

GAAP requires the mortality and improvement tables used in preparing these calculations to be appropriate for the employee base covered by the plan. Therefore, in 2014, KU's actuary, Towers Watson, performed an Experience and Demographic Assumptions Review of the Company's plan. Towers Watson reviewed the actual mortality experience for retirees and surviving spouses in the qualified pension plan. KU also reviewed a Mortality Credibility Analysis prepared by Towers Watson, which correlates the death experience of the KU pension plan participants to the new RP-2014 mortality tables.

KU reviewed the plan against the Total/No collar, Blue Collar and White Collar tables to find the best match. KU's experience deviated from the base table beyond a reasonable threshold, so the Company decided to make a corresponding adjustment of 2% to the White Collar table. The adjustment reduced the expected longevity of the participants, reducing the liability and future expense relative to the using the RP-2014 White Collar table. In addition, the Company reviewed US Census Bureau data that implied that death rates in Kentucky were higher than those in the overall United States, based on data from 2002 to 2008, to further support these adjustments.

KU adopted the BB-2 Dimensional improvement scale on a generational basis for its defined benefit pension and postretirement plans. KU acknowledges that mortality rates have and will continue to improve. However, we believe MP-2014 was based on an isolated period in which mortality improvement was at its highest level and thus would exaggerate continuing mortality improvements. Information available from the Human Mortality Database was reviewed for the period subsequent to the SOA study, which indicated a lower actual overall rate of improvement during this period. Social Security Administration information was also considered, to support the improvement scale assumption.

The SOA did not finalize the RP-2014 mortality tables until October 27, 2014. These tables were therefore not available when KU's actuary, Towers Watson, calculated the year-end 2013 liability in January 2014 and the 2014 expense in May 2014. The May 30, 2014 projections of 2015 expense were based upon exposure drafts of the RP-2014 tables. The adjustments to the RP-2014 tables and the replacement of the MP-2014 improvement factors with the Scale BB-2

Dimensional improvement factors were not reflected in the May 2014 projections proved by Towers Watson and used in the original rate case filing. Revised estimates using these updated assumptions and actual year-end 2014 discount rates have just been received by KU from its actuary. See response to PSC 3-5.

No. 2014-43
30 October 2014

To the Point

Benefit plan sponsors may need to consider new mortality tables in making year-end assumptions

Using the new mortality tables could increase a sponsor's benefit obligation.

What you need to know

- The Society of Actuaries finalized new mortality tables and a new mortality improvement scale that could increase a sponsor's benefit obligations and contributions.
- The new mortality information reflects improved life expectancies and an expectation that the trend will continue.
- Although sponsors are not required to use the tables or the improvement scale, they may need to consider the new mortality information when developing year-end mortality assumptions.
- Sponsors will need to provide year-end MD&A disclosures about any significant changes in their benefit obligations resulting from use of the tables. Sponsors that haven't issued interim financial statements for the latest period also should consider disclosures.
- If the new mortality tables are used for calculating plan sponsors' benefit costs and obligations, they should be consistently used for the plan's financial statements as well.

Overview

The Society of Actuaries (SOA)[1] issued new mortality tables (RP-2014) and a mortality improvement scale (MP-2014) that could increase a sponsor's obligations and contributions for defined benefit plans.

Because the new tables and improvement scale reflect today's longer life expectancies, plan sponsors may need to consider this new information (regardless of whether the plan is frozen) when measuring benefit costs and obligations that are based on the life expectancy of the participants in their plans. The tables and scale are not significantly different from the draft versions the SOA proposed earlier this year.

Sponsors that decide to use the new tables (or use them as a basis for their mortality rate assumptions) will need to determine which of the 11 tables or combination of tables are appropriate for their plans (the tables consider age, gender, income level and collar). Many sponsors that currently use the SOA's older mortality tables and scales are expected to use the new tables and scale, unless they have "credible" information supporting the use of a different table and scale.

Defined benefit plan sponsors are required to measure costs and obligations using their "best estimate" for the plan under Accounting Standards Codification (ASC) 715-30-35-42 and ASC 715-60-35-72. Such estimates should consider all available information as of the measurement date. Selecting appropriate assumptions is critical to measuring the components of a benefit plan and can significantly affect a sponsor's financial statements. The mortality rate is a key assumption used in valuing many retirement plans because it reflects the probability of future benefit payments that are contingent upon plan participants' life expectancies.

Key considerations

While use of the SOA tables is not required, the SOA is a leading authority on actuarial research, and a large number of plan sponsors use its mortality tables and mortality improvement scale as a starting point or basis to develop their mortality assumptions.

Plan sponsors will need to evaluate their mortality assumptions in light of longer life expectancies.

Sponsors that use other credible sources of mortality data may decide not to use the SOA's tables. For example, this may be the case for very large plans that have sufficient historical data and mortality experience or demographics that are inconsistent with the SOA's tables. Such circumstances may require a careful analysis by the sponsor, including consideration of changing trends in life expectancies.

In addition to a base table, mortality rate assumptions typically include a mortality improvement scale that addresses anticipated rates of improvement in life expectancy and the period over which those rates apply. Based on historical data, a sponsor may be able to use base mortality rates that differ from the SOA's tables to determine its best estimate. However, supporting customized improvement scales can be difficult.

It is important to note that the RP-2014 mortality tables were not yet available when the Internal Revenue Service issued Notice 2013-32, which identifies the older mortality tables that will be in use for minimum funding purposes for a plan's 2014 and 2015 plan years. If an entity uses the SOA tables as part of its estimation process, the new mortality tables should be considered and used consistently for estimating the plan sponsor's benefit costs and obligations, and the obligations presented in the benefit plan's financial statements that are measured subsequent to the issuance of the new mortality information.

Sponsors that plan to use the new tables should evaluate the effect on their financial statements and consider disclosing at year end the reasons for any significant changes in benefit obligations and the general approach used to estimate mortality rates in management's discussion and analysis (MD&A) under Item 303 of Regulation S-K and the retirement benefits footnote, respectively.

Sponsors that haven't yet issued their latest interim financial statements should consider MD&A disclosures if they anticipate significant changes in their benefit obligations resulting from use of the new tables.

Next steps

- Plan sponsors should discuss the final tables with their actuaries and auditors now. Sponsors will need to evaluate the effect of the new information on their mortality rate assumptions, which should represent the best estimate for each plan. Any conclusions should be supported by well-documented, robust analysis and credible statistics.
- The tables can be obtained on the SOA's web site, www.soa.org.

[1] The SOA is a professional organization committed to the development of the actuarial profession, the enhancement of actuarial-related research and the high standards of competency to which its members are held.

Audit and Enterprise Risk Services

Financial Reporting Considerations Related to Pension and Other Postretirement Benefits

Financial Reporting Alert 14-4
December 2, 2014

This publication, which updates Financial Reporting Alert 13-3, highlights accounting considerations related to the calculations and disclosures entities provide under U.S. GAAP in connection with their defined benefit pension and other postretirement benefit plans. This update includes a discussion of the new mortality tables and mortality improvement scale issued by the Society of Actuaries (SOA) Retirement Plans Experience Committee (RPEC) in October 2014.

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Underlying Assumptions

In measuring each plan's defined benefit obligation and recording the net periodic benefit cost, financial statement preparers should understand, evaluate, and reach conclusions about the reasonableness of the underlying assumptions, particularly those that could be affected by continuing financial market volatility. ASC 715-30-35-42[1] states that "each significant assumption used shall reflect the best estimate solely with respect to that individual assumption."

Entities should comprehensively assess the relevancy and reasonableness of each significant assumption on an ongoing basis (e.g., by considering the impact of significant developments that have occurred in the entity's business). Management should establish processes and internal controls to ensure that the entity appropriately selects each of the assumptions used in accounting for its defined benefit plans. The internal controls should be designed to ensure that the amounts reported in the financial statements properly reflect the underlying assumptions (e.g., discount rate, estimated long-term rate of return, mortality, turnover, health care costs) and that the documentation maintained in the entity's accounting records sufficiently demonstrates management's understanding of and reasons for using certain assumptions and methods (e.g., the method for determining the discount rate). Management should also document the key assumptions used and the reasons why certain assumptions may have changed from the prior reporting period. A leading practice is for management to prepare a memo supporting (1) the basis for each important assumption used and (2) how management determined which assumptions were important.

Mortality Assumption

Many entities rely on their actuarial firms for advice or recommendations concerning demographic assumptions, such as the mortality assumption. In many instances, actuaries recommend published tables that reflect broad-based studies of mortality. As stated above, under U.S. GAAP, each assumption should represent the "best estimate" for that assumption as of the current measurement date. The mortality tables used and adjustments made (e.g., for longevity improvements) should be appropriate for the employee base covered under the plan.

On October 27, 2014, the RPEC released a **report** on recent mortality experience of participants in private-sector single-employer pension plans, including a new set of mortality tables (RP-2014) and a new companion mortality improvement scale (MP-2014). The data underlying RP-2014 are based on a study of mortality experience in the period from 2004 through 2008, while the RP-2000 tables are based on data from 1990 through 1994, and Scale MP-2014 is based on more recent observed experience than the SOA's mortality projection Scales AA, BB, and BB-2D. The mortality improvement scale developed by the RPEC represents future expectations based on trend analysis from the data observed. In its report accompanying the new tables, the RPEC describes the process it undertook and how it considered the observed data when establishing the new mortality tables and improvement scale. These analyses show that longevity has improved more than expected by Scale AA derived from the prior mortality experience study.

Historically, many entities have used the RP-2000 tables and improvement Scale AA when selecting their mortality assumption. In selecting the year-end mortality assumption, entities should (1) carefully evaluate the RPEC's report, (2) obtain an understanding of the new RP-2014 mortality tables and MP-2014 improvement scale, and (3) consider the relevance of the data underlying such tables and improvement scale to the specific population covered by their defined benefit plans. In some circumstances, entities may also be able to consider other available information, such as plan-specific mortality experience, industry-specific mortality experience, or other relevant mortality experience. Entities should consider their rationale for changing the approach used in the prior year to select the mortality assumption (e.g., no longer using SOA-published tables or changing the extent to which longevity improvements are incorporated).

Editor's Note: Entities should robustly document their considerations (including any recommendations by their actuaries) in selecting this year's mortality assumptions for their defined benefit plans, including how they considered the SOA's reports on the new tables and longevity improvement scale. As discussed in **Underlying Assumptions** above, entities need to have processes and internal controls in place to ensure proper assessment of all relevant factors, including potentially contradictory data, when selecting the mortality assumption. Given the nature of the mortality assumption, we expect that many entities do not have such expertise internally. Therefore, it is important for entities to engage their actuarial firms early on when evaluating (1) the RP-2014 tables and longevity scale and (2) the effect of this new information on the mortality assumption for their benefit plans.

Because of the improved life expectancies indicated by the observed data underlying the RP-2014 tables, an entity's benefit obligation is likely to increase in the absence of changes in other plan assumptions. Further, a change in the mortality assumption could have a significant effect on the entity's results of operations, particularly if the entity's accounting policy is to recognize remeasurement gains and losses in net income immediately. Public entities should consider the requirement in ASC 715-20-50-1(r) to disclose an "explanation of any significant change in the benefit obligation or plan assets not otherwise apparent in the other disclosures required by [ASC 715-20]." In addition to footnote disclosures, SEC registrants should consider the need to highlight in MD&A the effects of a mortality assumption change. If other matters affecting an entity's defined benefit plans (e.g., changes in other assumptions, events such as curtailments or settlements) also result in changes to the retirement benefit obligation or net periodic benefit costs, an entity should consider separately disclosing the effects of each individually significant change.

The IRS's next update to its mandated mortality tables may well reflect the observed data underlying the RP-2014 tables, but that change is not expected until 2016 or 2017. Since the IRS is required by statute to update the required mortality assumption only once every 10 years, the fact that the IRS is not adopting the RP-2014 tables immediately should not affect an entity's determination of its best estimate for the mortality assumption for the current fiscal year. However, the IRS's future update of its mortality tables could lead to an increase in minimum funding requirements. As a result, an entity may need to (1) evaluate the effect of pension funding requirements on its liquidity, (2) consider adjusting its investment strategy accordingly, and (3) consider the need for discussion in MD&A of any expected changes in funding requirements.

Discount Rate

Discount Rate Selection Method

ASC 715-30-35-44 requires that the discount rate reflect rates at which the defined benefit obligation could be effectively settled. In estimating those rates, it would be appropriate for an entity to use information about rates implicit in current prices of annuity contracts that could be used to settle the obligation. Alternatively, employers may look to rates of return on high-quality fixed-income investments that are currently available and expected to be available during the benefits' period to maturity.

One acceptable method of deriving the discount rate would be to use a model that reflects rates of zero-coupon, high-quality corporate bonds with maturity dates and amounts that match the timing and amount of the expected future benefit payments. Since there are a limited number of zero-coupon corporate bonds in the market, models are constructed with coupon-paying bonds whose yields are adjusted to approximate results that would have been obtained through the use of the zero-coupon bonds. Constructing a hypothetical portfolio of high-quality instruments with maturities that mirror the benefit obligation is one method that can be used to achieve this objective. Other methods that can be expected to produce results that are not materially different would also be acceptable — for example, use of a yield curve constructed by a third party such as an actuarial firm. The use of indices may also be acceptable.

Entities should focus on the requirement to use the best estimate when determining their discount rate selection method. ASC 715-30-55-26 through 55-28 state that an entity may change its method of selecting discount rates provided that the method results in "the best estimate of the effective settlement rates" as of the current measurement date. This change would be viewed as a change in estimate, and the effect would be included in actuarial gains and losses and accounted for in accordance with ASC 715-30-35-18 through 35-21. When an entity's method of selecting a discount rate results in higher rates than those being used by similar entities or in rates that remain consistent from year to year despite a fluctuating market, questions may be raised about whether the method is producing a reasonable result.

Editor's Note: In determining the appropriate discount rate, entities should consider the following SEC staff guidance (codified in ASC 715-20-S99-1):

> At each measurement date, the SEC staff expects registrants to use discount rates to measure obligations for pension benefits and postretirement benefits other than pensions that reflect the then current level of interest rates. The staff suggests that fixed-income debt securities that receive one of the two highest ratings given by a recognized ratings agency be considered high quality (for example, a fixed-income security that receives a rating of Aa or higher from Moody's Investors Service, Inc.).

Hypothetical Bond Portfolios — Bond Pricing

Entities that use hypothetical bond portfolios (HBPs) to support the discount rate used to measure their postretirement benefit obligations should evaluate the impact of current market conditions on both bond pricing and bond selection. Credit market uncertainty may affect the level of trading activity for some bonds, resulting in large spreads between the bid and ask prices. Pricing should reflect the amount at which the postretirement benefit obligation could be settled. In the current market, bid price (which is often used because of the availability of data) may not necessarily represent the cost of acquiring a hypothetical portfolio. In evaluating the appropriateness of bond pricing used to develop their models, entities may find it helpful to consider the guidance in ASC 820-10-35-36C and 35-36D, which state, in part:

> If an asset or a liability measured at fair value has a bid price and an ask price (for example, an input from a dealer market), the price within the bid-ask spread that is most representative of fair value in the circumstances shall be used to measure fair value regardless of where the input is categorized within the fair value hierarchy (that is, Level 1, 2, or 3). . . . This Topic does not preclude the use of mid-market pricing or other pricing conventions that are used by market participants as a practical expedient for fair value measurements within a bid-ask spread.

Hypothetical Bond Portfolios — Bond Selection

In developing an HBP, entities must exclude certain bonds, known as "outliers." The discount rate may be affected by volatility in the financial markets and pending downgrades in the bond instruments that are used to develop the rate. Entities should exclude outliers from the HBP when developing discount rates for defined benefit plans; discount rates derived from HBPs, which generally include fewer bonds than third-party yield curves, are more significantly affected by inappropriately included outliers.

Outliers may include bonds that have high yields because:

- The issuer is on review for possible downgrade by one of the major rating agencies (only if the downgrade would cause the bond to no longer be considered high-quality).
- Recent events have caused significant price volatility, and the rating agencies have not yet reacted.
- The bond's lack of liquidity has caused price quotes to vary significantly from broker to broker.

Management should understand and evaluate the bonds in its HBPs to ensure that all outliers have been identified and excluded. Downgrades from high-quality to less than high-quality that occur shortly after the balance sheet date may indicate that a bond was an outlier on the balance sheet date, particularly if the bond was subject to a downgrade watch. Even after identifying and excluding outliers, entities should select a discount rate that is appropriate.

Entities must also consider whether a sufficient quantity of the selected bonds ("capacity") is currently available in the market to cover their postretirement benefit obligations. In other words, for a benefit obligation to be effectively settled, the value of the bonds in the hypothetical portfolio must be sufficient to match the timing and amount of expected benefit payments.

Hypothetical Bond Portfolios — Use of Collateralized Bonds

Some actuarial firms include collateralized bonds in the construction of HBPs. The rating of the bond and the related cash flows may achieve a rating of high-quality partly as a result of the collateral feature. The yields on these collateralized bonds may be higher than those on other comparably rated securities with the same duration. In other words, the bond may not be rated high-quality in the absence of the collateral feature. Depending on the facts and circumstances related to the terms of the bond, the collateral, and the issuer, collateralized bonds may be considered outliers that need to be removed from the HBP to achieve the appropriate discount rate. Entities will need to use judgment in evaluating whether collateralized bonds could be included in an HBP or whether a yield adjustment would be required for any such bonds included in an HBP. If a yield adjustment is required, entities should assess whether such an adjustment is objectively determinable.

Use of a Yield Curve Developed by a Third Party in Selecting a Discount Rate

As previously mentioned, an entity may elect to use a yield curve that was constructed by a third party to support its discount rate. Many yield curves constructed by third parties are supported by a white paper or other documentation that discusses how the yield curves are constructed. Management should understand how the yield curve it has used to develop its discount rate was constructed as well as the universe of bonds included in the analysis. If applicable, management should also evaluate and reach conclusions about the reasonableness of the approach the third party used to adjust the bond universe that was used to develop the yield curve.

In evaluating the inclusion of such bonds in a yield-curve analysis, entities should also consider the discussion above regarding inclusion of collateralized bonds in an HBP. Collateralized bonds may qualify for inclusion in a yield-curve bond universe if an entity can demonstrate that the collateralized bonds have been appropriately adjusted for, if necessary, or that the impact of the inclusion of the collateralized bonds does not significantly affect the discount rate derived from the yield curve.

We have been advised by some third parties, in particular those constructing yield curves for non-U.S. markets (e.g., eurozone and Canada), that because of a lack of sufficient high-quality instruments with longer maturities, they have employed a method in which they adjust yields of bonds that are not rated AA by an estimated credit spread to derive a yield representative of an AA-quality bond. This bond, as adjusted, is included in the bond universe when the third party constructs its yield curve. Management should understand the adjustments made to such bond yields in the construction of those yield curves and why those adjustments are appropriate.

Use of Indices in Selecting a Discount Rate

An entity may also select a discount rate by referring to index rates as long as the entity can demonstrate that the timing and amount of cash flows related to the bonds included in the index match its estimated defined benefit payments. An entity should consider whether the specific index reflects the market in a manner consistent with other similar indices and whether market conditions have affected the level of trading activity for bonds included in the index (as demonstrated by large spreads between the bid and ask prices). As noted above, pricing should reflect the amount at which the postretirement benefit obligation could be settled. The practice of using indices (with appropriate adjustments) is more prevalent for U.K. and other European plans because the high-quality bond universe in Europe is smaller than that in the United States; consequently, HBPs and yield curves are more difficult to construct for these plans.

Editor's Note: For eurozone and U.K. plans, discount rates may be selected from several available indices. Sources of these indices include Bloomberg, Reuters, and Markit.

Markit, which manages and administers the Markit iBoxx bond indices, states on its Web site that "Markit iBoxx [bond] indices are rebalanced monthly on the last business day of the month . . . . Changes in ratings are only taken into account if they are publicly known two business days before the end of the month." For example, under this method, bonds that have been downgraded in late November and that are no longer considered high-quality by iBoxx may be included in the construction of the November 30 indices (i.e., the indices may include bonds that are considered "outliers"). In addition, we have noted that a Markit iBoxx index may, on occasion, include a callable bond that could distort the index depending on the maturity assumed.

Entities that refer to indices when selecting their discount rate should determine whether it is appropriate to use them or whether it is necessary to make adjustments to the indices in addition to those made to reflect differences in timing of cash flows (e.g., removal of outliers and adjustments for callable bonds). In addition, management must be able to conclude that the results of using a shortcut to calculate its discount rate, such as an index, are reasonably expected not to be materially different from the results of using a discount rate calculated from a hypothetical portfolio of high-quality bonds.

Other Postretirement Benefit Plans — Discount Rate and Health Care Cost Trend Rate

ASC 715-60-20 defines "health care cost trend rate" as an "assumption about the annual rates of change in the cost of health care benefits currently provided by the postretirement benefit plan . . . . The health care cost trend rates implicitly consider estimates of health care inflation, changes in health care utilization or delivery patterns, technological advances, and changes in the health status of the plan participants." The health care cost trend rate is used to project the change in the cost of health care over the period for which the plan provides benefits to its participants. Many plans use trend rate assumptions that include (1) a rate for the year after the measurement date that reflects the recent trend of health care cost increases, (2) gradually decreasing trend rates for each of the next several years, and (3) an ultimate trend rate that is used for all remaining years.

Historically, the ultimate health care cost trend rate has been less than the discount rate. While discount rates have started to recover from their record lows in previous years, the discount rate for some plans has fallen below the ultimate health care cost trend rate. Some concerns have been raised regarding this phenomenon, since expectations of long-term inflation rates are assumed to be implicit in both the health care cost trend rate and the discount rate. In such situations, entities should consider all the facts and circumstances of their plan(s) to determine whether the assumptions used (e.g., ultimate health care cost trend rate of 5 percent and discount rate of 4 percent) are reasonable. Entities should also remember that (1) the discount rate reflects spot rates observable in the market as of the plan's measurement date, since it represents the rates at which the defined benefit obligation could be effectively settled on that date (given the rates implicit in current prices of annuity contracts or the rates of return on high-quality fixed-income investments that are currently available and expected to be available during the benefits' period to maturity), and (2) the health care cost trend rate is used to project the change in health care costs over the long term.

Expected Long-Term Rate of Return

The expected long-term rate of return on plan assets[2] is a component of an entity's net periodic benefit cost and should represent the average rate of earnings expected over the long term on the funds invested to provide future benefits (existing plan assets and contributions expected during the current year). The long-term rate of return is set as of the beginning of an entity's fiscal year (e.g., January 1, 2014, for a calendar-year-end entity). If the target allocation has changed from the prior year, an entity should consider whether adjusting its assumption about the long-term rate of return is warranted.

Some entities engage an external investment adviser to actively manage their portfolios of plan assets. In calculating the expected long-term rate of return, such entities may include an adjustment ("alpha" adjustment) to increase the rate of return to reflect their expectations that actively managed portfolios will generate higher returns than portfolios that are not actively managed. If an entity adjusts for "alpha," management should support its assumption that returns will exceed overall market performance plus management fees. Such support would most likely include a robust analysis of the historical performance of the plan assets.

As with the discount rate, an entity should understand, evaluate, and reach conclusions about the reasonableness of the expected long-term rate of return on plan assets. To determine the expected long-term rate of return, management must make assumptions about the future performance of each class of plan assets on the basis of both historical results and current market information. Management's documentation supporting these assumptions should contain details about the expected return for each asset category, including (1) an analysis of how the expected return compares with historical returns and (2) the impact of current trends related to economic conditions, inflation, and market sentiment.

Net Periodic Benefit Cost

Entities should consider the effect of the gain or loss amortization component of net periodic benefit cost. Many entities record the minimum amortization amount (the excess outside the "corridor").[3] The amortization is based on accumulated gain or loss as of the beginning of the year. Accordingly, the change in discount rates and favorable asset returns in equity markets in 2014 will not affect net periodic benefit cost until the following year.

Changes to Accounting Policies for Gains and Losses and Market-Related Value of Plan Assets

An entity may consider moving to a "mark-to-market" approach in which it immediately recognizes actuarial gains and losses as a component of net periodic benefit cost. Any change in the amortization method selected for gains and losses is considered a change in accounting policy accounted for in accordance with ASC 250. Once an entity changes to an approach in which net gains and losses are more rapidly amortized, the preferability of a subsequent change to a method that results in slower amortization would be difficult to support.

As with all defined benefit retirement plans, plan sponsors' use of computational shortcuts and estimates is appropriate "provided the results are reasonably expected not to be materially different from the results of a detailed application."[4] Entities that use the mark-to-market approach should be vigilant when using shortcuts and approximations, since all changes in the measurement of the benefit obligation and plan assets immediately affect net periodic benefit cost.

The "market-related value of plan assets" is used to calculate the expected return on plan assets component of net periodic benefit cost. ASC 715-30-20 indicates that this value can be either "fair value or a calculated value that recognizes changes in fair value in a systematic and rational manner over not more than five years." The method used to calculate the market-related value must also be applied consistently from year to year for each asset class. If an entity changes from using a calculated value to using fair value in determining the expected return on plan assets, the changes in the expected return will more closely align with changes in the actual return on plan assets. Generally, a change from the use of a calculated value to fair value is a change to a preferable method because it accelerates the recognition in earnings of events that have already occurred.

Editor's Note: When entities adopt a policy to immediately recognize actuarial gains and losses as a component of net periodic pension cost, they may have presented non-GAAP financial measures that "remove the actual gain or loss from the performance measure and include an expected long-term rate of return."[5] The SEC noted that, in the absence of sufficient quantitative context about the nature of the adjustment, such measures may confuse investors. The staff suggested that registrants clearly label such adjustments and avoid the use of confusing or unclear terms in their disclosures.

For more information, see Deloitte's **Financial Reporting Alert 11-2, *Pension Accounting Considerations Related to Changes in Amortization Policy for Gains and Losses and in the Market-Related Value of Plan Assets***.

Measurement Date for Plan Assets and Benefit Obligations

Measurement of Plan Assets

In accordance with ASC 715-30-35-63, preparers should ensure that they use actual market values as of the measurement date (e.g., their fiscal year-end) for assets with readily determinable fair values. Entities should value assets without readily determinable fair values (e.g., alternative investments) as of the measurement date by applying ASC 820's principles on estimating the fair value of financial assets in inactive markets. For example, ASC 820-10-15-4 provides guidance on using net asset value per share (provided by an investee) to estimate the fair value of an alternative investment.

Editor's Note: Management is responsible for measuring the benefit plan assets at fair value and for providing related disclosures in the financial statements. To fulfill this responsibility, management should develop a financial accounting and reporting process that includes (1) using appropriate valuation methods, (2) supporting significant assumptions used to determine fair value, (3) documenting the valuation of the plan assets, and (4) ensuring that such fair value measurements are accounted for and reported in accordance with the entity's accounting policies and U.S. GAAP. Management may seek input from outside investment managers on the mechanics of valuing certain plan assets but must have sufficient knowledge to evaluate and independently challenge such valuation.

On October 14, 2014, as part of its **simplification initiative**,[6] the FASB issued a **proposed ASU**[7] to amend the measurement-date guidance in ASC 715. The proposed ASU contains a practical expedient that would allow an employer whose fiscal year-end does not fall on a calendar month-end (e.g., an entity that has a 52- or 53-week fiscal year), to measure retirement benefit obligations and related plan assets as of the month-end that is closest to the employer's fiscal year-end. The expedient would need to be elected as an accounting policy and be consistently applied. Because third-party plan asset custodians often provide information about fair value and classes of assets only as of the month-end, such an accounting policy would relieve the employer from adjusting the asset information to the appropriate fair values as of its fiscal year-end. The proposed ASU would be applied prospectively. However, the FASB has not decided on the effective date or whether early adoption would be permitted. Comments on the proposed ASU are due by December 15, 2014.

Measurement of Benefit Obligations

An entity must measure benefit obligations on a plan-by-plan basis by using the discount rate as of the measurement date (e.g., the entity's fiscal year-end). Because of market volatility, it may be difficult for an entity to demonstrate that an adjusted discount rate based on a rollforward of a discount rate from an earlier date would meet the requirements of ASC 715. Under ASC 715-30-35-1 and ASC 715-60-35-1, an entity may employ computational shortcuts if the results are "reasonably expected not to be materially different from the results of a detailed application." Accordingly, preparers should maintain sufficient evidence that this requirement has been met. Such evidence should include a calculation of the benefit obligation, as of the measurement date, by using a discount rate that reflects inputs as of the measurement date. Any material difference that the entity does not record would be deemed an error.

Curtailments

Over the past few years, many entities have sought to reduce operating costs by amending their defined benefit plans to eliminate benefits for future service. This elimination of benefits could be classified as either of the following:

- *Hard freeze* — An amendment to a defined benefit plan that permanently eliminates future benefit accruals.
- *Soft freeze* — An amendment to a defined benefit plan that eliminates benefits for future service but takes into account salary increases in the determination of the benefit obligation for prior service.

The *FASB Accounting Standards Codification* defines a plan curtailment as an "event that significantly reduces the [aggregate] expected years of future service of present employees or eliminates for a significant number of employees the accrual of defined benefits for some or all of their future services." Generally, a hard freeze that represents a permanent suspension of benefits is treated as a curtailment for accounting purposes. The guidance on accounting for soft freezes is unclear, and views differ on whether to treat a soft freeze as a plan amendment or a curtailment. Those that view a soft freeze as a curtailment note that the measurement of the projected benefit obligation takes into account salary increases. We believe that an entity may treat a soft freeze as either a plan amendment or a curtailment. An entity should choose one of these two alternatives as an accounting policy and consistently apply its accounting election.

Other events, such as corporate restructurings or plant shutdowns, could also trigger curtailment accounting. An entity should assess each of these events on the basis of its particular facts and circumstances. Curtailments generally trigger an interim remeasurement date in a manner similar to other significant events that occur during a fiscal year.

Settlements

Some entities may institute restructuring programs that include a reduction in workforce. Such entities may have pension plans that permit employees to elect to receive their pension benefit in a lump sum, which could result in multiple lump-sum payments over the course of the year. Accordingly, if the total of such lump-sum payments made during the year is significant, settlement accounting could be required under ASC 715.

Under ASC 715-30-35-82, if a settlement has occurred, any gain or loss from the settlement should be recognized in earnings "if the cost of all settlements during a year is greater than the sum of the service cost and interest cost components of net periodic pension cost for the pension plan for the year." Alternatively, if an entity adopts an accounting policy to apply settlement accounting to a settlement or settlements that are below the service-cost-plus-interest-cost threshold, the policy must be applied to all settlements.

Questions have arisen about how settlements that occur in an interim period should be accounted for when it is probable that the cumulative settlements for the year are expected to exceed the service-cost-plus-interest-cost threshold. On at least a quarterly basis, an entity should assess whether it is probable that the criteria for settlement accounting will be met (e.g., the total settlements will exceed the threshold). If the entity concludes that it is probable that the threshold will be exceeded during the year, the entity should apply settlement accounting on at least a quarterly basis rather than wait for the threshold to be exceeded on a year-to-date basis. Accordingly, as the settlements occur, and at least quarterly, the entity should complete a full remeasurement of its pension obligations and plan assets in accordance with ASC 715-30-35. Applying settlement accounting at quarter-end would be an acceptable practical accommodation unless, under the circumstances, the assumptions and resulting calculations indicate that using the exact date within the quarter would result in a materially different outcome.

Plan Sponsor Disclosures

Fair Value Measurement Disclosures

Because a sponsor's fair value measurement disclosures related to defined benefit plan assets are outside the scope of ASC 820, the FASB separately addressed a sponsor's fair value disclosures that are specific to its retirement plans. In accordance with ASC 715-20-50-1(d)(iv) for public entities or ASC 715-20-50-5(c)(iv) for nonpublic entities, the sponsor must disclose information about the fair value measurements of plan assets separately for each annual period for each class of plan assets.

Implementation issues have arisen about these disclosures, primarily about the Level 3 reconciliation disclosure. The FASB's rationale for requiring this disclosure is identical to its rationale for requiring the Level 3 reconciliation under ASC 820, except that gains and losses reported in earnings during the period must be presented separately from those recognized in other comprehensive income. We understand that the FASB will accept presentation alternatives as long as the rollforward disclosure meets the objective under ASC 715-20-50-1(d)(4) (ASC 715-20-50-5(c)(4) for nonpublic entities) of showing the "effect of fair value measurements using significant unobservable inputs (Level 3) on changes in plan assets **for the period**" (emphasis added).

Entities With Foreign Plans

The SEC staff sometimes requests registrants to support their basis for combining pension and other postretirement benefit plan disclosures for U.S. and non-U.S. plans. ASC 715-20-50-4 states that a "U.S. reporting entity may combine disclosures about pension plans or other postretirement benefit plans outside the United States with those for U.S. plans unless the benefit obligations of the plans outside the United States are significant relative to the total benefit obligation and those plans use significantly different assumptions."

Recent SEC Views

Recently, the SEC staff has addressed topics related to pension and other postretirement benefits because of factors such as the low-interest-rate environment, optionality in U.S. GAAP accounting methods, and significant assumptions used in the measurement of the benefit obligation. The staff has noted that it particularly focuses on the discount rate and the expected return on plan assets. In addition, the staff has indicated that it may be appropriate for a registrant to disclose the following:

- Whether a corridor is used to amortize the actuarial gains and losses; and, if so, how the corridor is determined and the period for amortization of the actuarial gains and losses in excess of the corridor.
- A sensitivity analysis estimating the effect of a change in assumption regarding the long-term rate of return. This estimate should be based on a reasonable range of likely outcomes.
- The extent to which historical performance was used to develop the expected long-term rate of return assumption. If use of the arithmetic mean to calculate the historical returns yields results that are materially different from the results yielded when the geometric mean is used to calculate such returns, it may be appropriate for an entity to disclose both calculations.
- The reasons why the assumption regarding the long-term rate of return has changed or is expected to change in the future.

For more information, see Deloitte's ***SEC Comment Letters — Including Industry Insights: A Recap of Recent Trends***.

Health Care Reform

Affordable Care Act and Health Care and Education Reconciliation Act of 2010

Entities need to continue to consider the impact on postretirement benefits of the Patient Protection and Affordable Care Act and the Health Care and Education Reconciliation Act of 2010 (collectively, the "Act"). The passage of the Act has resulted in comprehensive health care reform since its March 2010 enactment, with this reform continuing over the next several years. The Act, among other things, eliminated the annual and lifetime benefit caps on essential health benefits and imposed an excise tax on high-cost employer health plans. An entity should account for the Act's effects, such as the excise tax on high-cost plans, on the basis of the provisions of its current substantive benefit plans even if it is considering amending its plans before the related provision of the Act becomes effective.

Employee Group Waiver Plans

Before the Act, employers offering retiree prescription drug coverage that was at least as valuable as Medicare Part D coverage were entitled to a tax-free 28 percent federal retiree drug subsidy (RDS). Employers could claim a deduction for the entire cost of providing the prescription drug coverage even though a portion of the cost is offset by the subsidy they receive. The Act repealed the rule permitting deduction of the portion of the drug coverage expense that is offset by the Medicare Part D subsidy, effective in 2013. However, the Act made certain enhancements to Medicare Part D prescription drug coverage and introduced other provisions to address Medicare Part D coverage gaps, including a pharmaceutical manufacturers' 50 percent discount on brand-name drugs beginning in 2011, increasing to a 75 percent discount on brand-name drugs and expanding to include discounted generic drugs by 2020.

Employers either can continue to apply for federal RDS payments that are received by the employer directly or they can sponsor a Medicare Part D plan through an employee group waiver plan (EGWP)[8] to take advantage of the enhancements under the Act (via cost savings passed along from the health care plan administrator). An

EGWP is designed to provide benefits that are actuarially equivalent to Medicare Part D and must be run by the health care plan administrator.

It is generally expected that retiree plan participants will receive essentially the same prescription drug benefits under an EGWP as they would under an RDS approach. However, the cost of providing the benefit will generally be less. Depending on the specific plan design for cost sharing between the employer and the retiree, the cost savings may be realized by either party or both parties. If the benefits provided by the plan to the participants do not change as a result of the change from the RDS to an EGWP, only the assumption regarding plan costs has changed and the employer will record an actuarial gain. However, if a change from an RDS to an EGWP involves a “substantive” change to the plan benefits, that part of the change should be accounted for as a plan amendment due to a change in benefits provided to participants by the plan. For example, if the cost savings of the EGWP are shared between the plan sponsor and the retirees, a change to the benefits the plan provides would generally result and the employer should recognize a plan amendment under ASC 715-60-35. Furthermore, the timing of accounting for the plan amendment may need to be considered, depending on (1) whether the employer has the unilateral ability to make the change, (2) how changes to the substantive plan are communicated to participants and the detail and timing of this communication, and (3) the significance of the changes. Entities need to consider the potential effects of any such plan amendments that are made concurrently with their open-enrollment period for 2015, which will typically take place in late 2014, and recognize the accounting effects of any significant changes in the period of the change (e.g., the fourth quarter of 2014).

Private Health Care Exchanges

Some entities have either stopped or are planning to stop providing retiree health care benefits through an employer-sponsored health care plan. Instead, they will provide those retirees with annual vouchers or contributions, often via a health retirement account, that the retiree can use to purchase insurance from private health care exchanges. These private health care exchanges offer a range of plans that provide coverage similarly to how the plans offered through the public exchanges set up under the Act provide coverage. If the retiree chooses a plan that costs more than the employer’s annual contribution to the retiree, he or she will have to pay the extra costs. Employers will make contributions during the retiree’s lifetime such that the entity retains mortality risk. When an entity ceases providing retiree health care benefits through an employer-sponsored plan and starts making annual contributions to the retiree or via a health retirement account, it has not settled the defined benefit obligation because the entity is still exposed to mortality risk. However, the entity’s defined benefit obligation has shifted to a plan that provides fixed annual contributions. This change should be accounted for as a plan amendment in accordance with ASC 715-60-35. Depending on the terms of the original entity-administered health plan, this type of amendment may either increase benefits (a positive plan amendment) or reduce benefits (a negative plan amendment).

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1 For titles of *FASB Accounting Standards Codification* references, see Deloitte’s “Titles of Topics and Subtopics in the ***FASB Accounting Standards Codification***.”

2 As defined in ASC 715-30, the “expected return on plan assets is determined based on the expected long-term rate of return on plan assets and the market-related value of plan assets.”

3 ASC 715-30-35-24 provides guidance on net periodic pension benefit cost and defines the corridor as “10 percent of the greater of the projected benefit obligation or the market-related value of plan assets.” Likewise, ASC 715-60-35-29 provides guidance on net periodic postretirement benefit cost and defines the corridor as “10 percent of the greater of the accumulated postretirement benefit obligation or the market-related value of plan assets.”

4 Excerpted from ASC 715-30-35-1 and ASC 715-60-35-1.

5 For more information, see the **highlights** of the June 27, 2012, CAQ SEC Regulations Committee joint meeting with the SEC staff.

6 Launched in June 2014, the FASB's simplification initiative is intended to reduce the cost and complexity of current U.S. GAAP while maintaining or enhancing the usefulness of the related financial statement information. The initiative focuses on narrow-scope projects that involve limited changes to guidance.

7 FASB Proposed Accounting Standards Update, *Practical Expedient for the Measurement Date of an Employer's Defined Benefit Obligation and Plan Assets*.

8 An EGWP could be structured as either (1) a self-insured program in which employers and union plans contract directly with the Centers for Medicare and Medicaid Services for benefits or (2) an insured program in which plan sponsors contract with a third party to provide prescription drug coverage to retirees.

AICPA®

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Technical Questions and Answers

Section 3700, *Pension Obligations*

.01 Effect of New Mortality Tables on Nongovernmental Employee Benefit Plans (EBPs) and Nongovernmental Entities That Sponsor EBPs

Inquiry—Nongovernmental EBPs and nongovernmental entities that sponsor EBPs (sponsoring entities) incorporate assumptions about participants' mortality in the calculation of the benefit liability for financial reporting purposes. Professional associations of actuaries occasionally publish updated mortality tables and mortality improvement projection scales (collectively referred to as *mortality tables* for purposes of this Technical Question and Answer) to reflect changes in mortality conditions based on recent historical trends and data. Established actuarial companies also may develop mortality tables based on other information and assumptions. For financial reporting purposes, how and when should nongovernmental EBPs and nongovernmental sponsoring entities consider these updated mortality tables if their financial statements have not yet been issued at the time the updated mortality tables are published?

Reply—Nongovernmental EBPs and nongovernmental sponsoring entities should consider the specific requirements of generally accepted accounting principles (GAAP), which require the use of a mortality assumption that reflects the best estimate of the plan's future experience for purposes of estimating the plan's obligation[1] as of the current measurement date (that is, the date at which the obligation is presented in the financial statements). In making this estimate, GAAP requires that all available information through the date the financial statements are available to be issued should be evaluated to determine if the information provides additional evidence about conditions that existed at the balance sheet date.

FASB *Accounting Standards Codification* (ASC) 855-10-55-1 specifies that information that becomes available after the balance sheet date (but before the financial statements are available to be issued)

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[1] Obligations that use a mortality assumption include, but are not limited to, defined benefit obligations under pension and other postretirement plans, and certain postemployment and deferred compensation arrangements. In accordance with paragraphs 18 and 21 of FASB *Accounting Standards Codification* (ASC) 715-30-35 and FASB ASC 960-20-35-4, changes in actuarial assumptions result in gains and losses that are recognized as they arise, and the comparative obligation amounts that have been previously reported would not be adjusted for issuance of updated mortality tables.

may be indicative of conditions existing at the balance sheet date when that information is a culmination of conditions that existed over a long period of time. Updated mortality tables are based on historical trends and data that go back many years; therefore, the existence of updated mortality conditions is not predicated upon the date that the updated mortality tables are published. Management of a nongovernmental EBP or a nongovernmental sponsoring entity should understand and evaluate the reasonableness of the mortality assumption chosen, even when assisted by an actuary acting as a management's specialist, and document its evaluation and the basis for selecting the mortality tables it decided to use for its current financial reporting period. A management's specialist is defined in paragraph .05 of AU-C section 500, *Audit Evidence* (AICPA, *Professional Standards*), as an individual or organization possessing expertise in a field other than accounting or auditing, whose work in that field is used by the entity to assist the entity in preparing the financial statements.

Many defined benefit pension plans present plan obligations as of the beginning of the plan year, as allowed under FASB ASC 960-205-45-1. Although this presentation is before the balance sheet date, it represents a measurement of an amount that is presented in the financial statements that should reflect management's best estimate of the plan's mortality and other assumptions. The assumptions used to estimate the plan's obligation should be evaluated based on all available information through the date the financial statements are available to be issued, including determining whether updated mortality conditions existed as of the date the obligation is presented in the financial statements (that is, the beginning of the year).

Auditors are required to evaluate the competence, capabilities, and objectivity of a management's specialist; obtain an understanding of the work of that specialist; and evaluate the appropriateness of that specialist's work as audit evidence for the relevant assertion. Considerations may include evaluating the relevance and reasonableness of significant assumptions and methods used by that specialist. Refer to paragraphs .08 and .A35–.A49 of AU-C section 500 and the "Using the Work of a Specialist" section in chapter 2, "Planning and General Auditing Considerations," of the AICPA Audit and Accounting Guide *Employee Benefit Plans*, for further guidance. In addition, the auditor is responsible for evaluating subsequent events under AU-C section 560, *Subsequent Events and Subsequently Discovered Facts* (AICPA, *Professional Standards*). That section requires the auditor to obtain sufficient appropriate audit evidence about whether events occurring between the date of the financial statements and the date of the auditor's report that require adjustment of, or disclosure in, the financial statements are appropriately reflected in those financial statements in accordance with the applicable financial reporting framework.

[Issue Date: February 2015.]

KENTUCKY UTILITIES COMPANY

CASE NO. 2014-00371

Response to Second Set of Data Requests of
Kentucky Industrial Utility Customers, Inc.
Dated February 6, 2015

Question No. 2-4

Responding Witness: Daniel K. Arbough

Q.2-4. Please indicate whether the Companies' actual pension and OPEB expense for 2014 as well as the related balance sheet assets and liabilities recorded as of December 31, 2014 reflected the RP-2014 mortality table. If not, please explain why not. In addition, identify all authorities relied on for the delay in adopting the RP-2014 mortality table for 2014 accounting and financial reporting purposes.

A.2-4. KU's pension and OPEB expenses for 2014 did not reflect the RP-2014 mortality tables because the tables were not available when the expenses were calculated by the Company's actuary.

KU's benefit obligations, which are reflected as liabilities in its financial statements as of December 31, 2014, do reflect the RP-2014 mortality tables, as adjusted as described in the response to Question No. 2-3.

See the response to Question No. 2-3 for additional information about KU's analysis and timing of the implementation of the RP-2014 mortality tables.

KENTUCKY UTILITIES COMPANY

CASE NO. 2014-00371

Response to Second Set of Data Requests of
Kentucky Industrial Utility Customers, Inc.
Dated February 6, 2015

Question No. 2-5

Responding Witness: Daniel K. Arbough

Q.2-5. Please provide the Companies' pension and OPEB expense recorded in their accounting books for January 2015 and the basis for the expense that was recorded, including the mortality table that was used for the expense. Please reconcile the amounts that were recorded to the Towers Watson actuarial costs for 2015.

A.2-5. The pension and OPEB expense that KU recorded on its accounting books for January 2015 is shown in the table below. It was based on expense projections provided by Towers Watson on May 30, 2014. This expense is allocated through KU's burdening process based on labor charges. Prior to issuing public financial statements, KU posts true-up entries to record the difference between the actuary's projected year to date expense and the amount that has been recorded based on labor burdens. These entries will eliminate the variances noted in the table below.

	January 2015 Expense	
	Pension	Postretirement
Per 5/30/14 Towers Watson Report	2,285,957	409,478
Per General Ledger	2,279,402	387,063
Variance	(6,554)	(22,415)

The mortality table used for the January 2015 expense is the RP-2014 mortality table with MP-2014 projection scale with white collar adjustment and is based on the Towers Watson 2015 expense projection dated May 30, 2014. (See attachment to KIUC 1-16.)

In addition to the variance true-up described above, the year-to-date expense will be revised based upon the updated expense estimates proved by Towers Watson on February 6, 2015. (See the response to PSC 3-5). The expense will ultimately be adjusted again to reflect final 2015 expense when that number becomes available in May 2015.

KENTUCKY UTILITIES COMPANY

CASE NO. 2014-00371

Response to Second Set of Data Requests of
Kentucky Industrial Utility Customers, Inc.
Dated February 6, 2015

Question No. 2-6

Responding Witness: Daniel K. Arbough

Q.2-6. Refer to the Company's response to KIUC 1-20. The question was as follows:

> *Please provide the Company's pension cost calculations for each year 2008 through 2014, the base year, and the test year, showing for each of those years the vintage year gains and losses and the calculation of the amortization of the gains and losses associated with each of those vintage years.*

In its response, the Company provided a schedule that had only a single line for (gain)/loss amortizations and did not provide the information requested in KIUC 1-20. Please provide the information that was requested and in the format that was requested in sufficient detail to replicate the calculation of the amounts reflected in each year referenced in the question. In addition, please provide this information in electronic format.

A.2-6. See Attachment 1 for 2008 - 2014. See Attachment 2 for 2014-2016, base year and test year.

DETERMINATION OF THE NET PERIODIC PENSION COST FOR THE FISCAL YEAR BEGINNING JANUARY 1, 2014 AND ENDING DECEMBER 31, 2014

LG&E and KU Energy LLC
Prior Service Cost Bases and Amortizations as of 12/31/2013

	Amount Remaining on Initial Base	Amortization	Period Remaining
LG&E and KU Retirement Plan			
[redacted]			
KU (Regulatory) Base 1	1,331,280	665,642	2.00
KU (Regulatory) Base 2	6,950	2,316	3.00
KU (Regulatory) Base 3	5,746	1,436	4.00
KU (Regulatory) Base 4	10,436	2,610	4.00
KU (Regulatory) Base 5	5,628	1,408	4.00
KU (Regulatory) Base 6	21,603	4,320	5.00
KU (Regulatory) Base 7	69,878	13,976	5.00
[redacted]			

[redacted]

LG&E and KU Postretirement Benefit Plan

[redacted]

PPL Corporation
LG&E and KU Energy LLC
Calculation of Market Related Value of Assets (MRV) for 1/1/2014

	LG&E and KU Retirement Plan 1/1/2014
EROA Prior Year	7.10%
Assumed Date of Disbursements	7/1/2013
Assumed Date of Employee Contributions	N/A
Actual Date of Employer Contribution	1/15/2013
MRV Prior Year	749,348,003
Disbursements	(46,232,580)
Employer Contribution	139,300,000
Employee Contributions	0
Expected Return	61,068,129
Expected MRV Current Year	903,483,552
Fair Value (FV) Current Year	889,265,217
MRV Current Year (80% of Expected MRV + 20% of FV)	900,639,886

[redacted]

PPL Corporation
LG&E and KU Energy LLC
Amortization of Net Actuarial (Gain)/Loss for 1/1/2014

[redacted]

	LG&E and KU Retirement Plan 1/1/2014
Fair Value of Assets	889,265,217
Market Related Value of Assets	900,639,886
PBO/APBO	960,426,685
Amortization of Net Actuarial (Gain)/Loss*	
Net Actuarial (Gain)/Loss	113,255,050
Deferred Asset Gain/(Loss)	(11,374,669)
Remaining Actuarial (Gain)/Loss	101,880,381
10% corridor	96,280,001
30% corridor	288,840,004
Excess 10% corridor	64,943,926
Excess 30% corridor	0
Average Future Service**	9.494
Amortization	6,840,523

*For the LG&E and KU Retirement Plan [redacted] (gain)/loss amortization is calculated under each company allocation and then added together for the plan's total. For this reason, the amortization amount shown cannot be calculated based on the total gains/losses and corridors shown above.

[redacted]

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DETERMINATION OF THE NET PERIODIC PENSION COST FOR THE FISCAL YEAR BEGINNING JANUARY 1, 2013 AND ENDING DECEMBER 31, 2013

LG&E AND KU ENERGY LLC RETIREMENT PLANS

MARCH 2013

MARSH & McLENNAN COMPANIES

Net Periodic Pension Cost

Service Cost, Interest Cost And Expected Return on Assets for Qualified Plans

		NonUnion Retirement Plan		
	[redacted]	ServCo	KU	[redacted]
Service Cost				
1. Service cost at beginning of year		$ 12,404,487	$ 7,892,652	
2. Interest for year		528,431	336,227	
3. Service cost at end of year		$ 12,932,918	$ 8,228,879	
Interest Cost				
1. Projected benefit obligation		$ 417,323,115	$ 414,139,917	
2. a. Expected distributions		5,609,320	17,548,378	
b. Weighted for timing		3,038,382	9,505,371	
3. Average projected benefit obligation		414,284,733	404,634,546	
4. Discount rate		4.26%	4.26%	
5. Interest cost		$ 17,648,530	$ 17,237,432	
Expected Return on Assets				
1. Market-related value of assets		$ 265,369,125	$ 299,675,383	
2. a. Expected distributions		5,609,320	17,548,378	
b. Weighted for timing		3,038,382	9,505,371	
3. a. Expected employer contributions		48,300,000	59,400,000	
b. Weighted for timing		46,287,500	56,925,000	
4. Average expected market-related value of assets		308,618,243	347,095,012	
5. Assumed rate of return		7.10%	7.10%	
6. Expected return on assets		$ 21,911,895	$ 24,643,746	

Attachment #1 to Response to KU KIUC-2 Question No. 6
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Arbough

Net Periodic Pension Cost

Gain/Loss Amortization Amount For Regulatory Accounting Purposes for Qualified Plans

		NonUnion Retirement Plan		
		ServCo	KU	
a. Projected benefit obligation	[redacted]	$ 417,323,115	$ 414,139,917	[redacted]
b. Fair value of plan assets		277,180,145	311,536,110	
c. Unrecognized transition (asset)/obligation		0	0	
d. Unrecognized prior service cost		13,958,602	2,143,235	
e. Cumulative ER contributions in excess of NPBC		(19,047,056)	31,828,783	
f. Unrecognized (gain)/loss (a-b-c-d+e)		107,137,312	132,289,355	
g. Market-related value of plan assets		265,369,125	299,675,383	
h. Excess of fair value over market-related value (b-g)		11,811,020	11,860,727	
i. Unrecognized (gain)/loss potentially subject to amortization (f+h)		118,948,332	144,150,082	
j. 10% of the larger of a or g		41,732,312	41,413,992	
k. 30% of the larger of a or g		125,196,935	124,241,975	
l. Unrec. (gain)/loss subject to standard amortization		77,216,020	82,827,983	
m. Unrec. (gain)/loss subject to accelerated amortization		0	19,908,107	
n. Unrecognized (gain)/loss subject to amortization (Total)		77,216,020	102,736,090	
o. Average years of future service		9.63	9.63	
p. One-half average years of future service		4.82	4.82	
q. Standard amortization amount (l / o)		8,018,278	8,601,037	
r. Accelerated amortization amount (m / p)		0	4,130,313	
s. Amortization amount (total) (q + r)		$ 8,018,278	$ 12,731,350	

Gain/Loss Amortization Amount For Financial Accounting Purposes for Qualified Plans

		NonUnion Retirement Plan		
		ServCo	KU	
a. Projected benefit obligation	[redacted]	$ 417,323,115	$ 414,139,917	[redacted]
b. Fair value of plan assets		277,180,145	311,536,110	
c. Unrecognized transition (asset)/obligation		0	0	
d. Unrecognized prior service cost		0	0	
e. Cumulative ER contributions in excess of NPBC		(112,633,948)	(73,683,942)	
f. Unrecognized (gain)/loss (a-b-c-d+e)		27,509,022	28,919,865	
g. Market-related value of plan assets		265,369,125	299,675,383	
h. Excess of fair value over market-related value (b-g)		11,811,020	11,860,727	
i. Unrecognized (gain)/loss potentially subject to amortization (f+h)		39,320,042	40,780,592	
j. 10% of the larger of a or g		41,732,312	41,413,992	
k. 30% of the larger of a or g		125,196,935	124,241,975	
l. Unrec. (gain)/loss subject to standard amortization		0	0	
m. Unrec. (gain)/loss subject to accelerated amortization		0	0	
n. Unrecognized (gain)/loss subject to amortization (Total)		0	0	
o. Average years of future service		9.63	9.63	
p. One-half average years of future service		4.82	4.82	
q. Standard amortization amount (l / o)		0	0	
r. Accelerated amortization amount (m / p)		0	0	
s. Amortization amount (total) (q + r)		$ 0	$ 0	

Net Periodic Pension Cost

Other Amortization Amounts - Non-Union Plan (ServCo Division)

Regulatory Accounting Purposes

	Unrecognized Amount as of January 1, 2013	Years Remaining	Annual Amortization Amount
1. Transition	$ 0	N/A	$ 0
2. Prior Service			
January 1, 1999	9,359	2.00	4,679
January 1, 2000	322,102	3.00	107,366
January 1, 2001	43,725	4.00	10,930
January 1, 2002	388,081	4.00	97,022
January 1, 2003	336,823	5.00	67,365
January 1, 2004	1,380,851	5.00	276,170
January 1, 2005	786,581	5.00	157,316
January 1, 2006	1,347,012	6.00	224,502
January 1, 2007	9,344,068	6.00	1,557,344
Total Prior Service	$ 13,958,602		$ 2,502,694

Financial Accounting Purposes

	Unrecognized Amount as of January 1, 2013	Years Remaining	Annual Amortization Amount
1. Transition	$ 0	N/A	$ 0
2. Prior Service	0	N/A	0
Total Prior Service	$ 0		$ 0

Net Periodic Pension Cost

Other Amortization Amounts - Non-Union Plan (KU Division)

Regulatory Accounting Purposes

	Unrecognized Amount as of January 1, 2013	Years Remaining	Annual Amortization Amount
1. Transition	$ 0	N/A	$ 0
2. Prior Service			
January 1, 2000	1,996,922	3.00	665,642
January 1, 2002	9,266	4.00	2,316
January 1, 2003	7,186	5.00	1,438
January 1, 2004	13,048	5.00	2,610
January 1, 2005	7,036	5.00	1,408
January 1, 2006	25,923	6.00	4,320
January 1, 2007	83,854	6.00	13,976
Total Prior Service	$ 2,143,235		$ 691,710

Financial Accounting Purposes

	Unrecognized Amount as of January 1, 2013	Years Remaining	Annual Amortization Amount
1. Transition	$ 0	N/A	$ 0
2. Prior Service	0	N/A	0
Total Prior Service	$ 0		$ 0

Plan Assets

Market Value of Assets for Qualified Plans

Plan	Market Value of Assets as of December 31, 2012
[redacted]	
LG&E and KU Energy LLC Non-Union	780,201,674
[redacted]	

The market value of assets for the divisions of the Non-Union Plan were provided by LG&E and KU Energy LLC and were adjusted below for transfers among the divisions.

	Non-Union Plan			
	[redacted]	ServCo	KU	[redacted]
1. Market value of assets on December 31, 2012 before adjustment for transfers	[redacted]	$274,002,971	$312,453,608	[redacted]
2. Adjustment for transfers	[redacted]	3,177,174	(917,498)	[redacted]
3. Market value of assets on December 31, 2012 after adjustment for transfers	[redacted]	$277,180,145	$311,536,110	[redacted]

Plan Assets

Market-Related Value of Assets – Non-Union Plan (ServCo Division)

1. Expected return			
a. Fair value as of January 1, 2012		$	228,380,881
b. Contributions weighted for timing			15,950,000
c. Benefit payments weighted for timing			1,281,061
d. Expenses weighted for timing			0
e. Time-weighted value of assets *(a. + b. – c. – d)*			243,049,820
f. Expected rate of return			7.25%
g. Expected return *(e. x f.)*		$	17,621,112
2. Actual return			
a. Fair value as of January 1, 2012		$	228,380,881
b. Contributions			17,600,000
c. Benefit payments			2,562,122
d. Expenses			0
e. Fair value at December 31, 2012			274,002,971
f. Actual return *(e. – a. – b. + c. + d.)*		$	30,584,212
3. Asset method base			
a. Expected return *(1.g.)*			17,621,112
b. Actual return *(2.f.)*			30,584,212
c. Gain (Loss) *(b. – a.)*		$	12,963,100

4. Actuarial adjustment

Valuation Date		Asset Method Base	Adjustment Factor		Adjustment
January 1, 2011	$	2,654,702	56.67%	$	(1,504,331)
January 1, 2012		(106,318)	60.00%		63,791
January 1, 2013		12,963,100	80.00%		(10,370,480)
Total adjustment				$	(11,811,020)

5. Fair value as of January 1, 2013 prior to adjustment for transfers	$	274,002,971
6. Adjustment for transfers		3,177,174
7. Actuarial adjustment		(11,811,020)
8. Market-related value *(5. + 6. +7.)*	$	265,369,125

Plan Assets

Market-Related Value of Assets – Non-Union Plan (KU Division)

1.	**Expected return**		
a.	Fair value as of January 1, 2012	$	280,602,839
b.	Contributions weighted for timing		14,183,333
c.	Benefit payments weighted for timing		8,471,615
d.	Expenses weighted for timing		0
e.	Time-weighted value of assets *(a. + b. – c. – d)*		286,314,557
f.	Expected rate of return		7.25%
g.	Expected return *(e. x f.)*	$	20,757,805
2.	**Actual return**		
a.	Fair value as of January 1, 2012	$	280,602,839
b.	Contributions		14,800,000
c.	Benefit payments		16,943,229
d.	Expenses		0
e.	Fair value at December 31, 2012		312,453,608
f.	Actual return *(e. – a. – b. + c. + d.)*	$	33,993,998
3.	**Asset method base**		
a.	Expected return *(1.g.)*		20,757,805
b.	Actual return *(2.f.)*		33,993,998
c.	Gain (Loss) *(b. – a.)*	$	13,236,193

4. **Actuarial adjustment**

Valuation Date	Asset Method Base	Adjustment Factor	Adjustment
January 1, 2011	$ 3,727,471	56.67%	$ (2,112,234)
January 1, 2012	(1,400,768)	60.00%	840,461
January 1, 2013	13,236,193	80.00%	(10,588,954)
Total adjustment			$ (11,860,727)

5.	**Fair value as of January 1, 2013 prior to adjustment for transfers**	$	312,453,608
6.	**Adjustment for transfers**		(917,498)
7.	**Actuarial adjustment**		(11,860,727)
8.	**Market-related value** *(5. + 6. + 7.)*	$	299,675,383

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DETERMINATION OF THE NET PERIODIC PENSION COST FOR THE FISCAL YEAR BEGINNING JANUARY 1, 2012 AND ENDING DECEMBER 31, 2012

LG&E AND KU ENERGY LLC RETIREMENT PLANS

NOVEMBER 2012

MARSH & McLENNAN COMPANIES

Net Periodic Pension Cost

Service Cost, Interest Cost And Expected Return on Assets for Qualified Plans

		NonUnion Retirement Plan		
	[redacted]	ServCo	KU	[redacted]
Service Cost				
1. Service cost at beginning of year		$ 10,476,600	$ 6,731,026	
2. Interest for year		536,402	344,629	
3. Service cost at end of year		**$ 11,013,002**	**$ 7,075,655**	
Interest Cost				
1. Projected benefit obligation		$ 331,690,928	$ 362,074,223	
2. a. Expected distributions		4,367,525	17,484,929	
b. Weighted for timing		2,365,743	9,471,003	
3. Average projected benefit obligation		329,325,185	352,603,220	
4. Discount rate		5.12%	5.12%	
5. Interest cost		**$ 16,861,449**	**$ 18,053,285**	
Expected Return on Assets				
1. Market-related value of assets		$ 226,430,663	$ 278,865,725	
2. a. Expected distributions		4,367,525	17,484,929	
b. Weighted for timing		2,365,743	9,471,003	
3. a. Expected employer contributions		15,600,000	14,800,000	
b. Weighted for timing		14,950,000	14,183,333	
4. Average expected market-related value of assets		239,014,920	283,578,055	
5. Assumed rate of return		7.25%	7.25%	
6. Expected return on assets		**$ 17,328,582**	**$ 20,559,409**	

Attachment #1 to Response to KU KIUC-2 Question No. 6
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Arbough

Net Periodic Pension Cost

Gain/Loss Amortization Amount For Regulatory Accounting Purposes for Qualified Plans

	[redacted]	NonUnion Retirement Plan ServCo	NonUnion Retirement Plan KU	[redacted]
a. Projected benefit obligation		$ 331,690,928	$ 362,074,223	
b. Fair value of plan assets		228,380,881	280,602,839	
c. Unrecognized transition (asset)/obligation		0	0	
d. Unrecognized prior service cost		16,464,530	2,834,945	
e. Cumulative ER contributions in excess of NPBC		(20,048,040)	29,823,564	
f. Unrecognized (gain)/loss (a-b-c-d+e)		66,797,477	108,460,003	
g. Market-related value of plan assets		226,430,663	278,865,725	
h. Excess of fair value over market-related value (b-g)		1,950,218	1,737,114	
i. Unrecognized (gain)/loss potentially subject to amortization (f+h)		68,747,695	110,197,117	
j. 10% of the larger of a or g		33,169,093	36,207,422	
k. 30% of the larger of a or g		99,507,278	108,622,267	
l. Unrec. (gain)/loss subject to standard amortization		35,578,602	72,414,845	
m. Unrec. (gain)/loss subject to accelerated amortization		0	1,574,850	
n. Unrecognized (gain)/loss subject to amortization (Total)		35,578,602	73,989,695	
o. Average years of future service		10.03	10.03	
p. One-half average years of future service		5.02	5.02	
q. Standard amortization amount (l / o)		3,547,219	7,219,825	
r. Accelerated amortization amount (m / p)		0	313,715	
s. Amortization amount (total) (q + r)		$ 3,547,219	$ 7,533,540	

Gain/Loss Amortization Amount For Financial Accounting Purposes for Qualified Plans

	[redacted]	NonUnion Retirement Plan ServCo	NonUnion Retirement Plan KU	[redacted]
a. Projected benefit obligation		$ 331,690,928	$ 362,074,223	
b. Fair value of plan assets		228,380,881	280,602,839	
c. Unrecognized transition (asset)/obligation		0	0	
d. Unrecognized prior service cost		0	0	
e. Cumulative ER contributions in excess of NPBC		(119,688,079)	(83,914,411)	
f. Unrecognized (gain)/loss (a-b-c-d+e)		(16,378,032)	(2,443,027)	
g. Market-related value of plan assets		226,430,663	278,865,725	
h. Excess of fair value over market-related value (b-g)		1,950,218	1,737,114	
i. Unrecognized (gain)/loss potentially subject to amortization (f+h)		(14,427,814)	(705,913)	
j. 10% of the larger of a or g		33,169,093	36,207,422	
k. 30% of the larger of a or g		99,507,278	108,622,267	
l. Unrec. (gain)/loss subject to standard amortization		0	0	
m. Unrec. (gain)/loss subject to accelerated amortization		0	0	
n. Unrecognized (gain)/loss subject to amortization (Total)		0	0	
o. Average years of future service		10.03	10.03	
p. One-half average years of future service		5.02	5.02	
q. Standard amortization amount (l / o)		0	0	
r. Accelerated amortization amount (m / p)		0	0	
s. Amortization amount (total) (q + r)		$ 0	$ 0	

Net Periodic Pension Cost

Other Amortization Amounts - Non-Union Plan (ServCo Division)

Regulatory Accounting Purposes

	Unrecognized Amount as of January 1, 2012	Years Remaining	Annual Amortization Amount
1. Transition	$ 0	N/A	$ 0
2. Prior Service			
January 1, 1998	3,234	1.00	3,234
January 1, 1999	14,038	3.00	4,679
January 1, 2000	429,468	4.00	107,366
January 1, 2001	54,655	5.00	10,930
January 1, 2002	485,103	5.00	97,022
January 1, 2003	404,188	6.00	67,365
January 1, 2004	1,657,021	6.00	276,170
January 1, 2005	943,897	6.00	157,316
January 1, 2006	1,571,514	7.00	224,502
January 1, 2007	10,901,412	7.00	1,557,344
Total Prior Service	$ 16,464,530		$ 2,505,928

Financial Accounting Purposes

	Unrecognized Amount as of January 1, 2012	Years Remaining	Annual Amortization Amount
1. Transition	$ 0	N/A	$ 0
2. Prior Service	0	N/A	0
Total Prior Service	$ 0		$ 0

Net Periodic Pension Cost

Other Amortization Amounts - Non-Union Plan (KU Division)

Regulatory Accounting Purposes

	Unrecognized Amount as of January 1, 2012	Years Remaining	Annual Amortization Amount
1. Transition	$ 0	N/A	$ 0
2. Prior Service			
January 1, 2000	2,662,564	4.00	665,642
January 1, 2002	11,582	5.00	2,316
January 1, 2003	8,624	6.00	1,438
January 1, 2004	15,658	6.00	2,610
January 1, 2005	8,444	6.00	1,408
January 1, 2006	30,243	7.00	4,320
January 1, 2007	97,830	7.00	13,976
Total Prior Service	$ 2,834,945		$ 691,710

Financial Accounting Purposes

	Unrecognized Amount as of January 1, 2012	Years Remaining	Annual Amortization Amount
1. Transition	$ 0	N/A	$ 0
2. Prior Service	0	N/A	0
Total Prior Service	$ 0		$ 0

Plan Assets

Market Value of Assets for Qualified Plans

Plan	Market Value of Assets as of December 31, 2011
[redacted]	
LG&E and KU Energy LLC Non-Union	684,070,619
[redacted]	

The market value of assets for the divisions of the Non-Union Plan were provided by LG&E and KU Energy LLC and were adjusted below for transfers among the divisions.

	Non-Union Plan			
	[redacted]	ServCo	KU	[redacted]
1. Market value of assets on December 31, 2011 before adjustment for transfers		$217,442,856	$285,107,981	
2. Adjustment for transfers		10,938,025	(4,505,142)	
3. Market value of assets on December 31, 2011 after adjustment for transfers		228,380,881	280,602,839	

Plan Assets

Market-Related Value of Assets – Non-Union Plan (ServCo Division)

1. Expected return		
a. Fair value as of January 1, 2011	$	166,987,326
b. Contributions weighted for timing		36,416,667
c. Benefit payments weighted for timing		1,054,254
d. Expenses weighted for timing		0
e. Time-weighted value of assets *(a. + b. – c. – d)*		202,349,739
f. Expected rate of return		7.25%
g. Expected return *(e. x f.)*	$	14,670,356
2. Actual return		
a. Fair value as of January 1, 2011	$	166,987,326
b. Contributions		38,000,000
c. Benefit payments		2,108,508
d. Expenses		0
e. Fair value at December 31, 2011		217,442,856
f. Actual return *(e. – a. – b. + c. + d.)*	$	14,564,038
3. Asset method base		
a. Expected return *(1.g.)*		14,670,356
b. Actual return *(2.f.)*		14,564,038
c. Gain (Loss) *(b. – a.)*	$	(106,318)

4. Actuarial adjustment

Valuation Date		Asset Method Base	Adjustment Factor		Adjustment
January 1, 2011	$	2,654,702	76.67%	$	(2,035,272)
January 1, 2012		(106,318)	80.00%		85,054
Total adjustment				$	(1,950,218)

5. Fair value as of January 1, 2012 prior to adjustment for transfers	$	217,442,856
6. Adjustment for transfers		10,938,025
7. Actuarial adjustment		(1,950,218)
8. Market-related value *(5. + 6. +7.)*	$	226,430,663

Plan Assets

Market-Related Value of Assets – Non-Union Plan (KU Division)

1.	**Expected return**		
a.	Fair value as of January 1, 2011	$	240,702,136
b.	Contributions weighted for timing		41,208,333
c.	Benefit payments weighted for timing		8,507,550
d.	Expenses weighted for timing		0
e.	Time-weighted value of assets *(a. + b. – c. – d)*		273,402,919
f.	Expected rate of return		7.25%
g.	Expected return *(e. x f.)*	$	19,821,712
2.	**Actual return**		
a.	Fair value as of January 1, 2011	$	240,702,136
b.	Contributions		43,000,000
c.	Benefit payments		17,015,099
d.	Expenses		0
e.	Fair value at December 31, 2011		285,107,981
f.	Actual return *(e. – a. – b. + c. + d.)*	$	18,420,944
3.	**Asset method base**		
a.	Expected return *(1.g.)*		19,821,712
b.	Actual return *(2.f.)*		18,420,944
c.	Gain (Loss) *(b. – a.)*	$	(1,400,768)

4. **Actuarial adjustment**

Valuation Date	Asset Method Base	Adjustment Factor	Adjustment
January 1, 2011	$ 3,727,471	76.67%	$ (2,857,728)
January 1, 2012	(1,400,768)	80.00%	1,120,614
Total adjustment			$ (1,737,114)

5.	**Fair value as of January 1, 2012 prior to adjustment for transfers**	$	**285,107,981**
6.	**Adjustment for transfers**		**(4,505,142)**
7.	**Actuarial adjustment**		**(1,737,114)**
8.	**Market-related value** *(5. + 6. + 7.)*	$	**278,865,725**

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CONSULTING. OUTSOURCING. INVESTMENTS.

November 2011

LG&E and KU Energy LLC Retirement Plans

Determination of the Net Periodic Pension Cost
for the Fiscal Year Beginning January 1, 2011 and Ending
December 31, 2011

MARSH & McLENNAN
COMPANIES

Net Periodic Pension Cost

Service Cost, Interest Cost And Expected Return on Assets for Qualified Plans

		NonUnion Retirement Plan			
	[redacted]	ServCo		KU	[redacted]
Service Cost					
1. Service cost at beginning of year		10,993,068	$	7,051,117	
2. Interest for year		606,817		389,222	
3. Service cost at end of year		**11,599,885**	**$**	**7,440,339**	
Interest Cost					
1. Projected benefit obligation		310,545,652	$	356,041,792	
2. a. Expected distributions		3,349,735		17,814,520	
b. Weighted for timing		1,814,440		9,649,532	
3. Average projected benefit obligation		308,731,212		346,392,260	
4. Discount rate		5.52%		5.52%	
5. Interest cost		**17,041,963**	**$**	**19,120,853**	
Expected Return on Assets					
1. Market-related value of assets		164,421,114	$	237,098,914	
2. a. Expected distributions		3,349,735		17,814,520	
b. Weighted for timing		1,814,440		9,649,532	
3. a. Expected employer contributions		38,000,000		43,000,000	
b. Weighted for timing		36,416,667		41,208,333	
4. Average expected market-related value of assets		199,023,341		268,657,715	
5. Assumed rate of return		7.25%		7.25%	
6. Expected return on assets		**14,429,192**	**$**	**19,477,684**	

Net Periodic Pension Cost

Gain/Loss Amortization Amount For Regulatory Accounting Purposes for Qualified Plans

		NonUnion Retirement Plan		
	[redacted]	ServCo	KU	[redacted]
a. Projected benefit obligation		310,545,652	$ 356,041,792	
b. Fair value of plan assets		166,987,326	240,702,136	
c. Unrecognized transition (asset)/obligation		0	0	
d. Unrecognized prior service cost		18,976,480	3,526,655	
e. (Accrued)/prepaid pension cost		(35,421,488)	3,972,368	
f. Unrecognized (gain)/loss (a-b-c-d+e)		89,160,358	115,785,369	
g. Market-related value of plan assets		164,421,114	237,098,914	
h. Excess of fair value over market-related value (b-g)		2,566,212	3,603,222	
i. Unrecognized (gain)/loss potentially subject to amortization (f+h)		91,726,570	119,388,591	
j. 10% of the larger of a or g		31,054,565	35,604,179	
k. 30% of the larger of a or g		93,163,696	106,812,538	
l. Unrec. (gain)/loss subject to standard amortization		60,672,005	71,208,359	
m. Unrec. (gain)/loss subject to accelerated amortization		0	12,576,053	
n. Unrecognized (gain)/loss subject to amortization (Total)		60,672,005	83,784,412	
o. Average years of future service		10.28	10.28	
p. One-half average years of future service		5.14	5.14	
q. Standard amortization amount (l / o)		5,901,946	6,926,883	
r. Accelerated amortization amount (m / p)		0	2,446,703	
s. Amortization amount (total) (q + r)		5,901,946	$ 9,373,586	

Gain/Loss Amortization Amount For Financial Accounting Purposes for Qualified Plans

		NonUnion Retirement Plan		
	[redacted]	ServCo	KU	[redacted]
a. Projected benefit obligation		310,545,652	$ 356,041,792	
b. Fair value of plan assets		166,987,326	240,702,136	
c. Unrecognized transition (asset)/obligation		0	0	
d. Unrecognized prior service cost		0	0	
e. (Accrued)/prepaid pension cost		(143,475,423)	(119,830,903)	
f. Unrecognized (gain)/loss (a-b-c-d+e)		82,903	(4,491,247)	
g. Market-related value of plan assets		164,421,114	237,098,914	
h. Excess of fair value over market-related value (b-g)		2,566,212	3,603,222	
i. Unrecognized (gain)/loss potentially subject to amortization (f+h)		2,649,115	(888,025)	
j. 10% of the larger of a or g		31,054,565	35,604,179	
k. 30% of the larger of a or g		93,163,696	106,812,538	
l. Unrec. (gain)/loss subject to standard amortization		0	0	
m. Unrec. (gain)/loss subject to accelerated amortization		0	0	
n. Unrecognized (gain)/loss subject to amortization (Total)		0	0	
o. Average years of future service		10.28	10.28	
p. One-half average years of future service		5.14	5.14	
q. Standard amortization amount (l / o)		0	0	
r. Accelerated amortization amount (m / p)		0	0	
s. Amortization amount (total) (q + r)		0	$ 0	

Net Periodic Pension Cost

Other Amortization Amounts - Non-Union Plan (ServCo Division)

Regulatory Accounting Purposes

	Unrecognized Amount as of January 1, 2011	Years Remaining	Annual Amortization Amount
1. Transition	$ 0	N/A	$ 0
2. Prior Service			
January 1, 1994	(7,318)	1.00	(7,318)
January 1, 1995	9,503	1.00	9,503
January 1, 1997	3,839	1.00	3,839
January 1, 1998	6,466	2.00	3,232
January 1, 1999	18,717	4.00	4,679
January 1, 2000	536,834	5.00	107,366
January 1, 2001	65,585	6.00	10,930
January 1, 2002	582,125	6.00	97,022
January 1, 2003	471,553	7.00	67,365
January 1, 2004	1,933,191	7.00	276,170
January 1, 2005	1,101,213	7.00	157,316
January 1, 2006	1,796,016	8.00	224,502
January 1, 2007	12,458,756	8.00	1,557,344
Total Prior Service	$ 18,976,480		$ 2,511,950

Financial Accounting Purposes

	Unrecognized Amount as of January 1, 2011	Years Remaining	Annual Amortization Amount
1. Transition	$ 0	N/A	$ 0
2. Prior Service	0	N/A	0
Total Prior Service	$ 0		$ 0

Net Periodic Pension Cost

Other Amortization Amounts - Non-Union Plan (KU Division)

Regulatory Accounting Purposes

	Unrecognized Amount as of January 1, 2011	Years Remaining	Annual Amortization Amount
1. Transition	$ 0	N/A	$ 0
2. Prior Service			
January 1, 2000	3,328,206	5.00	665,642
January 1, 2002	13,898	6.00	2,316
January 1, 2003	10,062	7.00	1,438
January 1, 2004	18,268	7.00	2,610
January 1, 2005	9,852	7.00	1,408
January 1, 2006	34,563	8.00	4,320
January 1, 2007	111,806	8.00	13,976
Total Prior Service	$ 3,526,655		$ 691,710

Financial Accounting Purposes

	Unrecognized Amount as of January 1, 2011	Years Remaining	Annual Amortization Amount
1. Transition	$ 0	N/A	$ 0
2. Prior Service	0	N/A	0
Total Prior Service	$ 0		$ 0

Plan Assets

Market Value of Assets for Qualified Plans

Plan	Market Value of Assets as of December 31, 2010
[redacted]	
LG&E and KU Energy LLC Non-Union	558,382,577
[redacted]	

The market value of assets for the divisions of the Non-Union Plan were provided by LG&E and KU Energy LLC and were adjusted below for transfers among the divisions.

	Non-Union Plan			
	[redacted]	ServCo	KU	[redacted]
1. Market value of assets on December 31, 2010 before adjustment for transfers		$165,902,432	$241,002,503	
2. Adjustment for transfers		1,084,894	(300,367)	
3. Market value of assets on December 31, 2010 after adjustment for transfers		166,987,326	240,702,136	

Plan Assets

Market-Related Value of Assets – Non-Union Plan (ServCo Division)

1. Expected return		
a. Fair value as of November 1, 2010	$	161,588,332
b. Contributions weighted for timing		0
c. Benefit payments weighted for timing		145,684
d. Expenses weighted for timing		0
e. Time-weighted value of assets *(a. + b. – c. – d)*		161,442,649
f. Expected rate of return		7.25%
g. Expected return *(e. x f. x 2/12)*	$	1,950,765
2. Actual return		
a. Fair value as of November 1, 2010	$	161,588,332
b. Contributions		0
c. Benefit payments		291,367
d. Expenses		0
e. Fair value at December 31, 2010		165,902,432
f. Actual return *(e. – a. – b. + c. + d.)*	$	4,605,467
3. Asset method base		
a. Expected return *(1.g.)*		1,950,765
b. Actual return *(2.f.)*		4,605,467
c. Gain (Loss) *(b. – a.)*	$	2,654,702

4. Actuarial adjustment

Valuation Date	Asset Method Base	Adjustment Factor	Adjustment
January 1, 2011	$ 2,654,702	96.67%	$ (2,566,212)
Total adjustment			$ (2,566,212)

5. Fair value as of January 1, 2011 prior to adjustment for transfers	$	165,902,432
6. Adjustment for transfers		1,084,894
7. Actuarial adjustment		(2,566,212)
8. Market-related value *(5. + 6. +7.)*	$	164,421,114

Plan Assets

Market-Related Value of Assets – Non-Union Plan (KU Division)

1.	**Expected return**		
	a. Fair value as of November 1, 2010	$	237,296,259
	b. Contributions weighted for timing		0
	c. Benefit payments weighted for timing		1,435,605
	d. Expenses weighted for timing		0
	e. Time-weighted value of assets *(a. + b. – c. – d)*		235,860,654
	f. Expected rate of return		7.25%
	g. Expected return *(e. x f. x 2/12)*	$	2,849,983
2.	**Actual return**		
	a. Fair value as of November 1, 2010	$	237,296,259
	b. Contributions		0
	c. Benefit payments		2,871,210
	d. Expenses		0
	e. Fair value at December 31, 2010		241,002,503
	f. Actual return *(e. – a. – b. + c. + d.)*	$	6,577,454
3.	**Asset method base**		
	a. Expected return *(1.g.)*		2,849,983
	b. Actual return *(2.f.)*		6,577,454
	c. Gain (Loss) *(b. – a.)*	$	3,727,471

4. **Actuarial adjustment**

Valuation Date	Asset Method Base	Adjustment Factor	Adjustment
January 1, 2011	$ 3,727,471	96.67%	$ (3,603,222)
Total adjustment			$ (3,603,222)

5.	**Fair value as of January 1, 2011 prior to adjustment for transfers**	$	241,002,503
6.	**Adjustment for transfers**		(300,367)
7.	**Actuarial adjustment**		(3,603,222)
8.	Market-related value *(5. + 6. +7.)*	$	237,098,914

February 2011

LG&E and KU Energy LLC

Retirement Plans

Determination of the Net Periodic Pension Cost
for the Two Month Period Beginning November 1, 2010
and Ending December 31, 2010

MERCER

Net Periodic Pension Cost

Service Cost, Interest Cost And Expected Return on Assets for Qualified Plans

		NonUnion Retirement Plan			
	[redacted]	ServCo		KU	[redacted]
Service Cost					
1. Service cost at beginning of period		1,902,301	$	1,220,832	
2. Interest for period		17,279		11,089	
3. Service cost at end of period		1,919,580	$	1,231,921	
Interest Cost					
1. Projected benefit obligation		302,349,654	$	355,528,759	
2. a. Expected distributions		469,360		2,950,537	
b. Weighted for timing		234,680		1,475,268	
3. Average projected benefit obligation		302,114,974		354,053,491	
4. Discount rate		5.45%		5.45%	
5. Interest cost (3. x 4. x 2/12)		2,744,211	$	3,215,986	
Expected Return on Assets					
1. Market-related value of assets		161,588,332	$	237,296,259	
2. a. Expected distributions		469,360		2,950,537	
b. Weighted for timing		234,680		1,475,268	
3. a. Expected employer contributions		0		0	
b. Weighted for timing		0		0	
4. Average expected market-related value of assets		161,353,652		235,820,991	
5. Assumed rate of return		7.25%		7.25%	
6. Expected return on assets (4. x 5. x 2/12)		1,949,690	$	2,849,504	

Net Periodic Pension Cost

Gain/Loss Amortization Amount For Regulatory Accounting Purposes for Qualified Plans

		NonUnion Retirement Plan		
	[redacted]	ServCo	KU	[redacted]
a. Projected benefit obligation	[redacted]	302,349,654	$ 355,528,759	[redacted]
b. Fair value of plan assets	[redacted]	161,588,332	237,296,259	[redacted]
c. Unrecognized transition (asset)/obligation	[redacted]	0	0	[redacted]
d. Unrecognized prior service cost	[redacted]	19,398,168	3,662,789	[redacted]
e. (Accrued)/prepaid pension cost	[redacted]	(31,365,998)	7,267,935	[redacted]
f. Unrecognized (gain)/loss (a-b-c-d+e)	[redacted]	89,997,156	121,837,646	[redacted]
g. Market-related value of plan assets	[redacted]	161,588,332	237,296,259	[redacted]
h. Excess of fair value over market-related value (b-g)	[redacted]	0	0	[redacted]
i. Unrecognized (gain)/loss potentially subject to amortization (f+h)	[redacted]	89,997,156	121,837,646	[redacted]
j. 10% of the larger of a or g	[redacted]	30,234,965	35,552,876	[redacted]
k. 30% of the larger of a or g	[redacted]	90,704,896	106,658,628	[redacted]
l. Unrec. (gain)/loss subject to standard amortization	[redacted]	59,762,191	71,105,752	[redacted]
m. Unrec. (gain)/loss subject to accelerated amortization	[redacted]	0	15,179,018	[redacted]
n. Unrecognized (gain)/loss subject to amortization (Total)	[redacted]	59,762,191	86,284,770	[redacted]
o. Average years of future service	[redacted]	10.83	10.83	[redacted]
p. One-half average years of future service	[redacted]	5.42	5.42	[redacted]
q. Standard amortization amount (l / o x 2/12)	[redacted]	919,701	1,094,271	[redacted]
r. Accelerated amortization amount (m / p x 2/12)	[redacted]	0	466,759	[redacted]
s. Amortization amount (total) (q + r)	[redacted]	919,701	$ 1,561,030	[redacted]

Gain/Loss Amortization Amount For Financial Accounting Purposes for Qualified Plans

		NonUnion Retirement Plan		
	[redacted]	ServCo	KU	[redacted]
a. Projected benefit obligation	[redacted]	$ 302,349,654	$ 355,528,759	[redacted]
b. Fair value of plan assets	[redacted]	161,588,332	237,296,259	[redacted]
c. Unrecognized transition (asset)/obligation	[redacted]	0	0	[redacted]
d. Unrecognized prior service cost	[redacted]	0	0	[redacted]
e. (Accrued)/prepaid pension cost*	[redacted]	(140,761,322)	(118,232,500)	[redacted]
f. Unrecognized (gain)/loss (a-b-c-d+e)	[redacted]	0	0	[redacted]

* Purchase accounting amount

Net Periodic Pension Cost

Other Amortization Amounts - Non-Union Plan (ServCo Division)

Regulatory Accounting Purposes

	Unrecognized Amount as of November 1, 2010	Years Remaining	Two Month Amortization Amount
1. Transition	$ 0	N/A	$ 0
2. Prior Service			
January 1, 1994	(8,537)	1.17	(1,219)
January 1, 1995	11,087	1.17	1,584
January 1, 1996	3,029	0.17	3,029
January 1, 1997	4,479	1.17	640
January 1, 1998	7,005	2.17	539
January 1, 1999	19,497	4.17	780
January 1, 2000	554,728	5.17	17,894
January 1, 2001	67,407	6.17	1,822
January 1, 2002	598,295	6.17	16,170
January 1, 2003	482,781	7.17	11,228
January 1, 2004	1,979,219	7.17	46,028
January 1, 2005	1,127,432	7.17	26,219
January 1, 2006	1,833,433	8.17	37,417
January 1, 2007	12,718,313	8.17	259,557
Total Prior Service	$ 19,398,168		$ 421,688

Financial Accounting Purposes

	Unrecognized Amount as of November 1, 2010	Years Remaining	Two Month Amortization Amount
1. Transition	$ 0	N/A	$ 0
2. Prior Service	0	N/A	0
Total Prior Service	$ 0		$ 0

Net Periodic Pension Cost

Other Amortization Amounts - Non-Union Plan (KU Division)

Regulatory Accounting Pusposes

	Unrecognized Amount as of November 1, 2010	Years Remaining	Two Month Amortization Amount
1. Transition	$ 0	N/A	$ 0
2. Prior Service			
January 1, 1994	20,849	0.17	20,849
January 1, 2000	3,439,146	5.17	110,940
January 1, 2002	14,284	6.17	386
January 1, 2003	10,302	7.17	240
January 1, 2004	18,703	7.17	435
January 1, 2005	10,087	7.17	235
January 1, 2006	35,283	8.17	720
January 1, 2007	114,135	8.17	2,329
Total Prior Service	$ 3,662,789		$ 136,134

Financial Accounting Purposes

	Unrecognized Amount as of November 1, 2010	Years Remaining	Two Month Amortization Amount
1. Transition	$ 0	N/A	$ 0
2. Prior Service	0	N/A	0
Total Prior Service	$ 0		$ 0

Plan Assets

Market-Related Value of Assets for Qualified Plans

The market-related value of assets used to compute the net periodic pension cost is equal to the actual market value of assets as shown below:

Plan	Market Value of Assets as of October 31, 2010
[redacted]	
LG&E and KU Energy LLC Non-Union	548,209,519
[redacted]	

The market value of assets for the divisions of the Non-Union Plan were provided by LG&E and KU Energy LLC.

	Non-Union Plan			
	[redacted]	ServCo	KU	[redacted]
Market value of assets on October 31, 2010	[redacted]	$161,588,332	$237,296,259	[redacted]

February 2011

LG&E and KU Energy LLC

Retirement Plans

Determination of the Net Periodic Pension Cost for the Ten Month Period Beginning January 1, 2010 and Ending October 31, 2010

MERCER

Net Periodic Pension Cost

Service Cost, Interest Cost And Expected Return on Assets for Qualified Plans

		NonUnion Retirement Plan		
	[redacted]	ServCo	KU	[redacted]
Service Cost	[redacted]			[redacted]
1. Service cost at beginning of year	[redacted]	$ 9,501,910	$ 6,100,554	[redacted]
2. Interest for year	[redacted]	582,467	373,964	[redacted]
3. **Service cost for year**	[redacted]	$ 10,084,377	$ 6,474,518	[redacted]
4. Portion of year	[redacted]	x 10/12	x 10/12	[redacted]
5. **Service cost for period**	[redacted]	$ 8,403,648	$ 5,395,432	[redacted]
Interest Cost	[redacted]			[redacted]
1. Projected benefit obligation	[redacted]	$ 250,520,014	$ 318,584,255	[redacted]
2. a. Expected distributions	[redacted]	2,816,161	17,703,221	[redacted]
b. Weighted for timing	[redacted]	1,525,421	9,589,245	[redacted]
3. Average projected benefit obligation	[redacted]	248,994,593	308,995,010	[redacted]
4. Discount rate	[redacted]	6.13%	6.13%	[redacted]
5. **Interest cost for year**	[redacted]	$ 15,263,369	$ 18,941,394	[redacted]
6. Portion of year	[redacted]	x 10/12	x 10/12	[redacted]
7. **Interest cost for period**	[redacted]	$ 12,719,474	$ 15,784,495	[redacted]
Expected Return on Assets	[redacted]			[redacted]
1. Market-related value of assets	[redacted]	$ 140,608,809	$ 219,124,355	[redacted]
2. a. Expected distributions	[redacted]	2,816,161	17,703,221	[redacted]
b. Weighted for timing	[redacted]	1,525,421	9,589,245	[redacted]
3. a. Expected employer contributions	[redacted]	8,700,000	12,800,000	[redacted]
b. Weighted for timing	[redacted]	8,337,500	12,266,667	[redacted]
4. Average expected market-related value of assets	[redacted]	147,420,888	221,801,777	[redacted]
5. Assumed rate of return	[redacted]	7.75%	7.75%	[redacted]
6. **Expected return on assets for year**	[redacted]	$ 11,425,119	$ 17,189,638	[redacted]
7. Portion of year	[redacted]	x 10/12	x 10/12	[redacted]
8. **Expected return on assets for period**	[redacted]	$ 9,520,933	$ 14,324,698	[redacted]

Net Periodic Pension Cost

Gain/Loss Amortization Amount For Regulatory Accounting Purposes for Qualified Plans

		NonUnion Retirement Plan		
		ServCo	KU	
a. Projected benefit obligation	[redacted]	$ 250,520,014	$ 318,584,255	[redacted]
b. Fair value of plan assets		140,608,809	219,124,355	
c. Unrecognized transition (asset)/obligation		0	0	
d. Unrecognized prior service cost		21,506,608	4,343,457	
e. (Accrued)/prepaid pension cost		(23,271,239)	7,444,133	
f. Unrecognized (gain)/loss (a-b-c-d-+e)		55,133,358	102,560,576	
g. Market-related value of plan assets		140,608,809	219,124,355	
h. Excess of fair value over market-related value (b-g)		0	0	
i. Unrecognized (gain)/loss potentially subject to amortization (f+h)		55,133,358	102,560,576	
j. 10% of the larger of a or g		25,052,001	31,858,426	
k. Unrecognized (gain)/loss subject to amortization		40,081,357	70,702,150	
l. Average years of future service		10.83	10.83	
m. Amortization amount for year		**$ 3,700,956**	**$ 6,528,361**	
n. Portion of year		x 10/12	x 10/12	
o. Amortization amount for period		**$ 3,084,130**	**$ 5,440,301**	

Gain/Loss Amortization Amount For Financial Accounting Purposes for Qualified Plans

		NonUnion Retirement Plan		
		ServCo	KU	
a. Projected benefit obligation	[redacted]	$ 250,520,014	$ 318,584,255	[redacted]
b. Fair value of plan assets		140,608,809	219,124,355	
c. Unrecognized transition (asset)/obligation		0	0	
d. Unrecognized prior service cost		20,043,426	208,303	
e. (Accrued)/prepaid pension cost		(42,582,760)	(4,894,091)	
f. Unrecognized (gain)/loss (a-b-c-d-+e)		47,285,019	94,357,506	
g. Market-related value of plan assets		140,608,809	219,124,355	
h. Excess of fair value over market-related value (b-g)		0	0	
i. Unrecognized (gain)/loss potentially subject to amortization (f+h)		47,285,019	94,357,506	
j. 10% of the larger of a or g		25,052,001	31,858,426	
k. Unrecognized (gain)/loss subject to amortization		22,233,018	62,499,080	
l. Average years of future service		10.83	10.83	
m. Amortization amount for year		**$ 2,052,910**	**$ 5,770,922**	
n. Portion of year		x 10/12	x 10/12	
o. Amortization amount for period		**$ 1,710,758**	**$ 4,809,102**	

Net Periodic Pension Cost

Other Amortization Amounts - Non-Union Plan (ServCo Division)

Regulatory Accounting Purposes

	Unrecognized Amount as of January 1, 2010	Years Remaining	Ten Month Amortization Amount
1. Transition	$ 0	N/A	$ 0
2. Prior Service			
January 1, 1994	(14,634)	2.00	(6,097)
January 1, 1995	19,007	2.00	7,920
January 1, 1996	18,174	1.00	15,145
January 1, 1997	7,679	2.00	3,200
January 1, 1998	9,698	3.00	2,693
January 1, 1999	23,396	5.00	3,899
January 1, 2000	644,200	6.00	89,472
January 1, 2001	76,515	7.00	9,108
January 1, 2002	679,147	7.00	80,852
January 1, 2003	538,918	8.00	56,137
January 1, 2004	2,209,361	8.00	230,142
January 1, 2005	1,258,529	8.00	131,097
January 1, 2006	2,020,518	9.00	187,085
January 1, 2007	14,016,100	9.00	1,297,787
Total Prior Service	$ 21,506,608		$ 2,108,440

Financial Accounting Purposes

	Unrecognized Amount as of January 1, 2010	Years Remaining	Ten Month Amortization Amount
1. Transition	$ 0	N/A	$ 0
2. Prior Service			
January 1, 2003	538,918	8.00	56,137
January 1, 2004	2,209,361	8.00	230,142
January 1, 2005	1,258,529	8.00	131,097
January 1, 2006	2,020,518	9.00	187,085
January 1, 2007	14,016,100	9.00	1,297,787
Total Prior Service	$ 20,043,426		$ 1,902,248

Net Periodic Pension Cost

Other Amortization Amounts - Non-Union Plan (KU Division)

Regulatory Accounting Pusposes

	Unrecognized Amount as of January 1, 2010	Years Remaining	Ten Month Amortization Amount
1. Transition	$ 0	N/A	$ 0
2. Prior Service			
January 1, 1994	125,092	1.00	104,243
January 1, 2000	3,993,848	6.00	554,702
January 1, 2002	16,214	7.00	1,930
January 1, 2003	11,500	8.00	1,198
January 1, 2004	20,878	8.00	2,175
January 1, 2005	11,260	8.00	1,173
January 1, 2006	38,883	9.00	3,600
January 1, 2007	125,782	9.00	11,647
Total Prior Service	$ 4,343,457		$ 680,668

Financial Accounting Purposes

	Unrecognized Amount as of January 1, 2010	Years Remaining	Ten Month Amortization Amount
1. Transition	$ 0	N/A	$ 0
2. Prior Service			
January 1, 2003	11,500	8.00	1,198
January 1, 2004	20,878	8.00	2,175
January 1, 2005	11,260	8.00	1,173
January 1, 2006	38,883	9.00	3,600
January 1, 2007	125,782	9.00	11,647
Total Prior Service	$ 208,303		$ 19,793

Plan Assets

Market-Related Value of Assets for Qualified Plans

The market-related value of assets used to compute the net periodic pension cost is equal to the actual market value of assets as shown below:

Plan	Market Value of Assets as of December 31, 2009
[redacted]	
LG&E and KU Energy LLC Non-Union	499,042,268
[redacted]	

The market value of assets for the divisions of the Non-Union Plan were provided by LG&E and KU Energy LLC and were adjusted below for transfers among the divisions for accounting purposes.

	Non-Union Plan			
	[redacted]	ServCo	KU	[redacted]
1. Market value of assets on December 31, 2009		$139,785,644	$219,282,611	
2. Adjustment for transfers		823,165	(158,256)	
3. Market value of assets on December 31, 2009 after adjustment for transfers		$140,608,809	$219,124,355	

December 2009

E.ON U.S. LLC

Retirement Plans

Determination of the Net Periodic Pension Cost and IFRS Cost for the Fiscal Year Beginning January 1, 2009 and Ending December 31, 2009

MERCER

MARSH MERCER KROLL
GUY CARPENTER OLIVER WYMAN

Net Periodic Pension Cost for FAS 87 Accounting Purposes

Service Cost, Interest Cost And Expected Return on Assets for Qualified Plans

	[redacted]	NonUnion Retirement Plan		[redacted]
		ServCo	KU	
Service Cost				
1. Service cost at beginning of year		$ 9,054,747	$ 5,779,663	
2. Interest for year		565,922	361,229	
3. Service cost at end of year		$ 9,620,669	$ 6,140,892	$
Interest Cost				
1. Projected benefit obligation		$ 219,854,205	$ 304,055,674	
2. a. Expected distributions		2,063,690	18,055,439	
b. Weighted for timing		1,117,832	9,780,029	
3. Average projected benefit obligation		218,736,373	294,275,645	
4. Discount rate		6.25%	6.25%	
5. interest cost		$ 13,671,023	$ 18,392,228	$
Expected Return on Assets				
1. Market-related value of assets		$ 107,748,290	$ 183,716,919	
2. a. Expected distributions		2,063,690	18,055,439	
b. Weighted for timing		1,117,832	9,780,029	
3. a. Expected employer contributions		7,800,000	13,300,000	
b. Weighted for timing		5,525,000	9,420,833	
4. Average expected market-related value of assets		112,155,458	183,357,723	
5. Assumed rate of return		8.25%	8.25%	
6. Expected return on assets		$ 9,252,825	$ 15,127,012	$

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Net Periodic Pension Cost for FAS 87 Accounting Purposes

Gain/Loss Amortization Amount For Regulatory Accounting Purposes for Qualified Plans

	[redacted]	NonUnion Retirement Plan		[redacted]
		ServCo	KU	
a. Projected benefit obligation		$219,854,205	$304,055,674	
b. Fair value of plan assets		107,748,290	183,716,919	
c. Unrecognized transition (asset)/obligation		0	0	
d. Unrecognized prior service cost		24,036,737	5,160,261	
e. (Accrued)/prepaid pension cost		(9,484,586)	13,038,249	
f. Unrecognized (gain)/loss (a-b-c-d-+e)		78,584,592	128,216,743	
g. Market-related value of plan assets		107,748,290	183,716,919	
h. Excess of fair value over market-related value (b-g)		0	0	
i. Unrecognized (gain)/loss potentially subject to amortization (f+h)		78,584,592	128,216,743	
j. 10% of the larger of a or g		21,985,421	30,405,567	
k. Unrecognized (gain)/loss subject to amortization		56,599,171	97,811,176	
l. Average years of future service		11.28	11.28	
m. Amortization amount		$5,017,657	$8,671,204	

Gain/Loss Amortization Amount For Financial Accounting Purposes for Qualified Plans

	[redacted]	NonUnion Retirement Plan		[redacted]
		ServCo	KU	
a. Projected benefit obligation		$219,854,205	$304,055,674	
b. Fair value of plan assets		107,748,290	183,716,919	
c. Unrecognized transition (asset)/obligation		0	0	
d. Unrecognized prior service cost		22,326,123	232,055	
e. (Accrued)/prepaid pension cost		(30,779,759)	(890,991)	
f. Unrecognized (gain)/loss (a-b-c-d-+e)		59,000,033	119,215,709	
g. Market-related value of plan assets		107,748,290	183,716,919	
h. Excess of fair value over market-related value (b-g)		0	0	
i. Unrecognized (gain)/loss potentially subject to amortization (f+h)		59,000,033	119,215,709	
j. 10% of the larger of a or g		21,985,421	30,405,567	
k. Unrecognized (gain)/loss subject to amortization		37,014,612	88,810,142	
l. Average years of future service		11.28	11.28	
m. Amortization amount		$3,281,437	$7,873,240	

[redacted]

Net Periodic Pension Cost for FAS 87 Accounting Purposes

Other Amortization Amounts - Non-Union Plan (ServCo Division)

Regulatory Accounting Purposes

	Unrecognized Amount as of January 1, 2009	Years Remaining	Annual Amortization Amount
1. Transition	$ 0	N/A	$ 0
2. Prior Service			
January 1, 1994	(21,950)	3.00	(7,316)
January 1, 1995	28,511	3.00	9,504
January 1, 1996	36,349	2.00	18,175
January 1, 1997	11,519	3.00	3,840
January 1, 1998	12,930	4.00	3,232
January 1, 1999	28,075	6.00	4,679
January 1, 2000	751,566	7.00	107,366
January 1, 2001	87,445	8.00	10,930
January 1, 2002	776,169	8.00	97,022
January 1, 2003	606,283	9.00	67,365
January 1, 2004	2,485,531	9.00	276,170
January 1, 2005	1,415,845	9.00	157,316
January 1, 2006	2,245,020	10.00	224,502
January 1, 2007	15,573,444	10.00	1,557,344
Total Prior Service	$ 24,036,737		$ 2,530,129

Financial Accounting Purposes

	Unrecognized Amount as of January 1, 2009	Years Remaining	Annual Amortization Amount
1. Transition	$ 0	N/A	$ 0
2. Prior Service			
January 1, 2003	606,283	9.00	67,365
January 1, 2004	2,485,531	9.00	276,170
January 1, 2005	1,415,845	9.00	157,316
January 1, 2006	2,245,020	10.00	224,502
January 1, 2007	15,573,444	10.00	1,557,344
Total Prior Service	$ 22,326,123		$ 2,282,697

Net Periodic Pension Cost for FAS 87 Accounting Purposes

Other Amortization Amounts - Non-Union Plan (KU Division)

Regulatory Accounting Pusposes

	Unrecognized Amount as of January 1, 2009	Years Remaining	Annual Amortization Amount
1. Transition	$ 0	N/A	$ 0
2. Prior Service			
January 1, 1994	250,186	2.00	125,094
January 1, 2000	4,659,490	7.00	665,642
January 1, 2002	18,530	8.00	2,316
January 1, 2003	12,938	9.00	1,438
January 1, 2004	23,488	9.00	2,610
January 1, 2005	12,668	9.00	1,408
January 1, 2006	43,203	10.00	4,320
January 1, 2007	139,758	10.00	13,976
Total Prior Service	$ 5,160,261		$ 816,804

Financial Accounting Purposes

	Unrecognized Amount as of January 1, 2009	Years Remaining	Annual Amortization Amount
1. Transition	$ 0	N/A	$ 0
2. Prior Service			
January 1, 2003	12,938	9.00	1,438
January 1, 2004	23,488	9.00	2,610
January 1, 2005	12,668	9.00	1,408
January 1, 2006	43,203	10.00	4,320
January 1, 2007	139,758	10.00	13,976
Total Prior Service	$ 232,055		$ 23,752

Plan Assets

Market-Related Value of Assets for Qualified Plans

The market-related value of assets used to compute the net periodic pension cost and IFRS pension cost is equal to the actual market value of assets as shown below:

Plan	Market Value of Assets as of December 31, 2008
[redacted]	
E.ON U.S. LLC Non-Union	409,566,830
[redacted]	

The market value of assets for the divisions of the Non-Union Plan were provided by E.ON U.S. LLC and were adjusted below for transfers among the divisions for FAS 87 accounting purposes.

		Non-Union Plan		
	[redacted]	ServCo	KU	[redacted]
1. Market value of assets on December 31, 2008		$107,302,751	$183,828,383	
2. Adjustment for transfers		445,539	(111,464)	
3. Market value of assets on December 31, 2008 after adjustment for transfers		$107,748,290	$183,716,919	

The market value of assets for the divisions of the Non-Union Plan were provided by E.ON U.S. LLC and were adjusted below for transfers among the divisions for IFRS accounting purposes.

		Non-Union Plan		
	[redacted]	ServCo	KU	[redacted]
1. Market value of assets on December 31, 2008		$107,328,648	$183,885,855	
2. Adjustment for transfers		446,437	(113,936)	
3. Market value of assets on December 31, 2008 after adjustment for transfers		$107,775,085	$183,771,919	

November 2008

E.ON U.S. LLC

Retirement Plans

Determination of the Net Periodic Pension Cost and
IFRS Cost for the Fiscal Year Beginning January 1, 2008
and Ending December 31, 2008

MERCER

MARSH MERCER KROLL
GUY CARPENTER OLIVER WYMAN

Net Periodic Pension Cost for FAS 87 Accounting Purposes

Service Cost, Interest Cost And Expected Return on Assets for Qualified Plans

		NonUnion Retirement Plan		
	[redacted]	ServCo	KU	[redacted]
Service Cost				
1. Service cost at beginning of year		$ 8,355,237	$ 5,124,628	
2. Interest for year		556,459	341,300	
3. Service cost at end of year		$ 8,911,696	$ 5,465,928	
Interest Cost				
1. Projected benefit obligation		$ 188,055,836	$ 284,352,904	
2. a. Expected distributions		1,410,650	18,367,264	
b. Weighted for timing		764,102	9,948,935	
3. Average projected benefit obligation		187,291,734	274,403,969	
4. Discount rate		6.66%	6.66%	
5. Interest cost		$ 12,473,629	$ 18,275,304	
Expected Return on Assets				
1. Market-related value of assets		$ 142,061,843	$ 263,164,823	
2. a. Expected distributions		1,410,650	18,367,264	
b. Weighted for timing		764,102	9,948,935	
3. a. Expected employer contributions		2,000,000	0	
b. Weighted for timing		1,416,667	0	
4. Average expected market-related value of assets		142,714,408	253,215,888	
5. Assumed rate of return		8.25%	8.25%	
6. Expected return on assets		$ 11,773,939	$ 20,890,311	

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Net Periodic Pension Cost for FAS 87 Accounting Purposes

Gain/Loss Amortization Amount For Regulatory Accounting Purposes for Qualified Plans

	[redacted]	NonUnion Retirement Plan ServCo	NonUnion Retirement Plan KU	[redacted]
a. Projected benefit obligation		$ 188,055,836	$ 284,352,904	
b. Fair value of plan assets		142,061,843	263,164,823	
c. Unrecognized transition (asset)/obligation		0	0	
d. Unrecognized prior service cost		26,566,866	6,021,571	
e. (Accrued)/prepaid pension cost		773,154	17,066,998	
f. Unrecognized (gain)/loss (a-b-c-d-+e)		20,200,281	32,233,508	
g. Market-related value of plan assets		142,061,843	263,164,823	
h. Excess of fair value over market-related value (b-g)		0	0	
i. Unrecognized (gain)/loss potentially subject to amortization (f+h)		20,200,281	32,233,508	
j. 10% of the larger of a or g		18,805,584	28,435,290	
k. Unrecognized (gain)/loss subject to amortization		1,394,697	3,798,218	
l. Average years of future service		12	12	
m. Amortization amount		$ 116,225	$ 316,518	

Gain/Loss Amortization Amount For Financial Accounting Purposes for Qualified Plans

	[redacted]	NonUnion Retirement Plan ServCo	NonUnion Retirement Plan KU	[redacted]
a. Projected benefit obligation		$ 188,055,836	$ 284,352,904	
b. Fair value of plan assets		$ 142,061,843	$ 263,164,823	
c. Unrecognized transition (asset)/obligation		0	0	
d. Unrecognized prior service cost		24,608,820	255,807	
e. (Accrued)/prepaid pension cost		(20,885,676)	1,983,682	
f. Unrecognized (gain)/loss (a-b-c-d-+e)		499,497	22,915,956	
g. Market-related value of plan assets		142,061,843	263,164,823	
h. Excess of fair value over market-related value (b-g)		0	0	
i. Unrecognized (gain)/loss potentially subject to amortization (f+h)		499,497	22,915,956	
j. 10% of the larger of a or g		18,805,584	28,435,290	
k. Unrecognized (gain)/loss subject to amortization		0	0	
l. Average years of future service		12	12	
m. Amortization amount		$ 0	$ 0	

Net Periodic Pension Cost for FAS 87 Accounting Purposes

Other Amortization Amounts - Non-Union Plan (ServCo Division)

Regulatory Accounting Purposes

	Unrecognized Amount as of January 1, 2008	Years Remaining	Annual Amortization Amount
1. Transition	$ 0	N/A	$ 0
2. Prior Service			
January 1, 1994	(29,266)	4.00	(7,316)
January 1, 1995	38,016	4.00	9,504
January 1, 1996	54,524	3.00	18,175
January 1, 1997	15,359	4.00	3,840
January 1, 1998	16,162	5.00	3,232
January 1, 1999	32,754	7.00	4,679
January 1, 2000	858,932	8.00	107,366
January 1, 2001	98,375	9.00	10,930
January 1, 2002	873,191	9.00	97,022
January 1, 2003	673,648	10.00	67,365
January 1, 2004	2,761,701	10.00	276,170
January 1, 2005	1,573,161	10.00	157,316
January 1, 2006	2,469,522	11.00	224,502
January 1, 2007	17,130,788	11.00	1,557,344
Total Prior Service	$ 26,566,866		$ 2,530,129

Financial Accounting Purposes

	Unrecognized Amount as of January 1, 2008	Years Remaining	Annual Amortization Amount
1. Transition	$ 0	N/A	$ 0
2. Prior Service			
January 1, 2003	673,648	10.00	67,365
January 1, 2004	2,761,701	10.00	276,170
January 1, 2005	1,573,161	10.00	157,316
January 1, 2006	2,469,522	11.00	224,502
January 1, 2007	17,130,788	11.00	1,557,344
Total Prior Service	$ 24,608,820		$ 2,282,697

Net Periodic Pension Cost for FAS 87 Accounting Purposes

Other Amortization Amounts - Non-Union Plan (KU Division)

Regulatory Accounting Pusposes

	Unrecognized Amount as of January 1, 2008	Years Remaining	Annual Amortization Amount
1. Transition	$ 0	N/A	$ 0
2. Prior Service			
January 1, 1990	44,506	1.00	44,506
January 1, 1994	375,280	3.00	125,094
January 1, 2000	5,325,132	8.00	665,642
January 1, 2002	20,846	9.00	2,316
January 1, 2003	14,376	10.00	1,438
January 1, 2004	26,098	10.00	2,610
January 1, 2005	14,076	10.00	1,408
January 1, 2006	47,523	11.00	4,320
January 1, 2007	153,734	11.00	13,976
Total Prior Service	$ 6,021,571		$ 861,310

Financial Accounting Purposes

	Unrecognized Amount as of January 1, 2008	Years Remaining	Annual Amortization Amount
1. Transition	$ 0	N/A	$ 0
2. Prior Service			
January 1, 2003	14,376	10.00	1,438
January 1, 2004	26,098	10.00	2,610
January 1, 2005	14,076	10.00	1,408
January 1, 2006	47,523	11.00	4,320
January 1, 2007	153,734	11.00	13,976
Total Prior Service	$ 255,807		$ 23,752

Plan Assets

Market-Related Value of Assets for Qualified Plans

The market-related value of assets used to compute the net periodic pension cost and IFRS pension cost is equal to the actual market value of assets as shown below:

Plan	Market Value of Assets as of December 31, 2007
[redacted]	[redacted]
E.ON U.S. LLC Non-Union	574,522,011
[redacted]	[redacted]

The market value of assets for the divisions of the Non-Union Plan were provided by E.ON U.S. LLC and were adjusted below for transfers among the divisions for FAS 87 accounting purposes.

	Non-Union Plan			
	[redacted]	ServCo	KU	[redacted]
1. Market value of assets on December 31, 2007	[redacted]	$140,756,891	$264,623,193	[redacted]
2. Adjustment for transfers	[redacted]	1,304,952	(1,458,370)	[redacted]
3. Market value of assets on December 31, 2007 after adjustment for transfers	[redacted]	$142,061,843	$263,164,823	[redacted]

The market value of assets for the divisions of the Non-Union Plan were provided by E.ON U.S. LLC and were adjusted below for transfers among the divisions for IFRS accounting purposes.

	Non-Union Plan			
	[redacted]	ServCo	KU	[redacted]
1. Market value of assets on December 31, 2007	[redacted]	$140,791,836	$264,700,055	[redacted]
2. Adjustment for transfers	[redacted]	1,304,426	(1,458,846)	[redacted]
3. Market value of assets on December 31, 2007 after adjustment for transfers	[redacted]	$142,096,262	$263,241,209	[redacted]

LG&E and KU Energy LLC
Prior Service Cost Bases and Amortizations

	2014 Amount Remaining on Initial Base	2014 Amortization	2014 Period Remaining	2015 Amount Remaining on Initial Base	2015 Amortization	2015 Period Remaining
LG&E and KU Retirement Plan	[redacted]					
KU (Regulatory) Base 1	1,331,280	665,642	2.00	665,638	665,638	1.00
KU (Regulatory) Base 2	6,950	2,316	3.00	4,634	2,316	2.00
KU (Regulatory) Base 3	5,748	1,438	4.00	4,310	1,438	3.00
KU (Regulatory) Base 4	10,438	2,610	4.00	7,828	2,610	3.00
KU (Regulatory) Base 5	5,628	1,408	4.00	4,220	1,408	3.00
KU (Regulatory) Base 6	21,603	4,320	5.00	17,283	4,320	4.00
KU (Regulatory) Base 7	69,878	13,976	5.00	55,902	13,976	4.00
KU (Regulatory) Base 8	N/A	N/A	N/A	5,049,386	565,441	8.93
Servco (Financial) Base 1	N/A	N/A	N/A	9,132,087	1,022,630	8.93

[redacted]

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LG&E and KU Energy LLC
Prior Service Cost Bases and Amortizations

	2016 Amount Remaining on Initial Base	2016 Amortization	2016 Period Remaining	Base Year Amortization	Test Year Amortization
LG&E and KU Retirement Plan	[redacted]				
KU (Regulatory) Base 1	0	0	-	665,641	332,819
KU (Regulatory) Base 2	2,318	2,316	1.00	2,316	2,316
KU (Regulatory) Base 3	2,872	1,438	2.00	1,438	1,438
KU (Regulatory) Base 4	5,218	2,610	2.00	2,610	2,610
KU (Regulatory) Base 5	2,812	1,408	2.00	1,408	1,408
KU (Regulatory) Base 6	12,963	4,320	3.00	4,320	4,320
KU (Regulatory) Base 7	41,926	13,976	3.00	13,976	13,976
KU (Regulatory) Base 8	4,483,945	565,441	7.93	94,240	565,441
Servco (Financial) Base 1	8,109,457	1,022,630	7.93	170,438	1,022,630
[redacted]					

[redacted]

[redacted]

PPL Corporation
LG&E and KU Energy LLC
Calculation of Market Related Value of Assets (MRV) for 1/1/2014

	LG&E and KU Retirement Plan **1/1/2014**	[redacted]
EROA Prior Year	7.10%	
Assumed Date of Disbursements	7/1/2013	
Assumed Date of Employee Contributions	N/A	
Actual Date of Employer Contribution	1/15/2013	
MRV Prior Year	749,348,003	
Disbursements	(46,232,580)	
Employer Contribution	139,300,000	
Employee Contributions	0	
Expected Return	61,068,129	
Expected MRV Current Year	903,483,552	
Fair Value (FV) Current Year	889,265,217	
MRV Current Year [80% of Expected MRV + 20% of FV]	900,639,886	

PPL Corporation
LG&E and KU Energy LLC
Calculation of Market Related Value of Assets (MRV) for 1/1/2015

	LG&E and KU Retirement Plan* **1/1/2015**	[redacted]
EROA Prior Year	7.00%	
Assumed Date of Disbursements	7/1/2014	
Assumed Date of Employee Contributions	N/A	
Actual Date of Employer Contribution	1/14/2014	
MRV Prior Year	883,079,509	
Disbursements	(53,567,506)	
Employer Contribution	35,100,000	
Employee Contributions	0	
Expected Return	62,308,978	
Expected MRV Current Year	926,920,981	
Fair Value (FV) Current Year	984,382,816	
MRV Current Year [80% of Expected MRV + 20% of FV]	938,413,349	

*Amounts shown for the LG&E and KU Retirement Plan exclude WKE

PPL Corporation
LG&E and KU Energy LLC
Calculation of Market Related Value of Assets (MRV) for 1/1/2016

	LG&E and KU Retirement Plan* **1/1/2016**	
EROA Prior Year	7.00%	[redacted]
Assumed Date of Disbursements	7/1/2015	
Assumed Date of Employee Contributions	N/A	
Actual Date of Employer Contribution	1/14/2015	
MRV Prior Year	938,413,349	
Disbursements	(38,475,794)	
Employer Contribution	35,500,000	
Employee Contributions	0	
Expected Return	66,737,546	
Expected MRV Current Year	1,002,175,101	
Fair Value (FV) Current Year	1,051,362,430	
MRV Current Year [80% of Expected MRV + 20% of FV]	1,012,012,567	

*Amounts shown for the LG&E and KU Retirement Plan exclude WKE

TOWERS WATSON

PPL Corporation
LG&E and KU Energy LLC
Amortization of Net Actuarial (Gain)/Loss for 1/1/2014

	LG&E and KU Retirement Plan **1/1/2014**	[redacted]
Fair Value of Assets	889,265,217	
Market Related Value of Assets	900,639,886	
PBO/APBO	960,426,685	
Amortization of Net Actuarial (Gain)/Loss*		
Net Actuarial (Gain)/Loss	113,255,050	
Deferred Asset Gain/(Loss)	(11,374,669)	
Remaining Actuarial (Gain)/Loss	101,880,381	
10% corridor	96,280,001	
30% corridor	288,840,004	
Excess 10% corridor	64,943,926	
Excess 30% corridor	0	
Average Future Service	9.494	
Amortization	6,840,523	

*For the LG&E and KU Retirement Plan [redacted] (gain)/loss amortization is calculated under each company allocation and then added together for the plan's total. For this reason, the amortization amount shown cannot be calculated based on the total gains/losses and corridors shown above.

PPL Corporation
LG&E and KU Energy LLC
Amortization of Net Actuarial (Gain)/Loss for 1/1/2015

	LG&E and KU Retirement Plan* **1/1/2015**	[redacted]
Fair Value of Assets	984,382,816	
Market Related Value of Assets	938,413,349	
PBO/APBO	1,185,013,372	
Amortization of Net Actuarial (Gain)/Loss***		
Net Actuarial (Gain)/Loss	251,876,943	
Deferred Asset Gain/(Loss)	45,969,467	
Remaining Actuarial (Gain)/Loss	297,846,410	
10% corridor	118,501,337	
30% corridor	355,504,012	
Excess 10% corridor	157,146,802	
Excess 30% corridor	22,198,270	
Average Future Service	8.930	
Amortization	22,569,243	

*Amounts shown for the LG&E and KU Retirement Plan exclude WKE and are shown on a US GAAP basis
[redacted]
***For the LG&E and KU Retirement Plan [redacted], (gain)/loss amortization is calculated under each company allocation and then added together for the plan's total. For this reason, the amortization amount shown cannot be calculated based on the total gains/losses and corridors shown above.

TOWERS WATSON

PPL Corporation
LG&E and KU Energy LLC
Amortization of Net Actuarial (Gain)/Loss for 1/1/2016

	LG&E and KU Retirement Plan* **1/1/2016**	
Fair Value of Assets	1,051,362,430	[redacted]
Market Related Value of Assets	1,012,012,567	
PBO/APBO	1,221,889,534	
Amortization of Net Actuarial (Gain)/Loss* **		
Net Actuarial (Gain)/Loss	226,089,838	
Deferred Asset Gain/(Loss)	39,349,863	
Remaining Actuarial (Gain)/Loss	265,439,701	
10% corridor	122,188,953	
30% corridor	366,566,860	
Excess 10% corridor	142,612,147	
Excess 30% corridor	638,600	
Average Future Service	8.430	
Amortization	17,068,724	

*Amounts shown for the LG&E and KU Retirement Plan exclude WKE and are shown on a US GAAP basis
[redacted]

***For the LG&E and KU Retirement Plan [redacted], (gain)/loss amortization is calculated under each company allocation and then added together for the plan's total. For this reason, the amortization amount shown cannot be calculated based on the total gains/losses and corridors shown above.

PPL Corporation
LG&E and KU Energy LLC
Amortization of Net Actuarial (Gain)/Loss for Base Year

	LG&E and KU Retirement Plan*	
Amortization	9,461,976	[redacted]

*Amounts shown for the LG&E and KU Retirement Plan exclude WKE and are shown on a US GAAP basis
[redacted]

PPL Corporation
LG&E and KU Energy LLC
Amortization of Net Actuarial (Gain)/Loss for Test Year

	LG&E and KU Retirement Plan*	
Amortization	19,818,984	[redacted]

*Amounts shown for the LG&E and KU Retirement Plan exclude WKE and are shown on a US GAAP basis
[redacted]

TOWERS WATSON

KENTUCKY UTILITIES COMPANY

CASE NO. 2014-00371

Response to Second Set of Data Requests of
Kentucky Industrial Utility Customers, Inc.
Dated February 6, 2015

Question No. 2-7

Responding Witness: Daniel K. Arbough

Q.2-7. Refer to the Company's response to KIUC 1-21(a). The question was as follows:

> *Please confirm that the IRS determines the minimum pension funding requirements pursuant to ERISA, but does not determine the amount of pension expense pursuant to GAAP. In its response, the Company neither confirmed nor denied. Please respond to the question that was posed and confirm or deny. If denied, then please explain your response.*

In its response, the Company neither confirmed nor denied. Please respond to the question that was posed and confirm or deny. If denied, then please explain your response.

A.2-7. Yes, the IRS determines minimum pension funding requirements pursuant to ERISA. The IRS does not determine the amount of pension expense pursuant to GAAP.

KU retains Towers Watson for the purpose of determining minimum required pension contributions in accordance with ERISA and the Internal Revenue Code.

The cost of KU's pension plan is determined by Towers Watson in accordance with GAAP, specifically ASC 715.

KENTUCKY UTILITIES COMPANY

CASE NO. 2014-00371

Response to Second Set of Data Requests of
Kentucky Industrial Utility Customers, Inc.
Dated February 6, 2015

Question No. 2-8

Responding Witness: Daniel K. Arbough

Q.2-8. Refer to the Company's response to KIUC 1-21(b). The question was as follows:

Please describe the status of any guidelines or requirements by the SOA or any other authoritative agency or industry association to use the RP-2014 Mortality Improvement Scale MP-2014.

In its response, the Company simply referred to its response to AG 1-15(c). In its response to AGI-15(c), the Company stated:

In 2014, KU'S actuary, Towers Watson, performed an Experience and Demographic Assumptions Review of the Company's plan. Towers Watson reviewed the actual mortality experience for retirees and surviving spouses in the qualified pension plan. Based on the results of this study, KU determined that the RP-2014 mortality table was the best estimate of actual experience available.

This response does not address the question posed by KIUC 1-2(b) as to whether the Company is required or when it is required to adopt the RP-2014 mortality table. Please respond to the question posed.

A.2-8. See the response to Question No. 2-3.

KENTUCKY UTILITIES COMPANY

CASE NO. 2014-00371

Response to Second Set of Data Requests of
Kentucky Industrial Utility Customers, Inc.
Dated February 6, 2015

Question No. 2-9

Responding Witness: Valerie L. Scott

Q.2-9. Refer to the Company's response to KIUC 1-28. Please provide a copy of the electronic spreadsheet with all formulas intact.

A.2-9. See the attachment being provided in Excel format.

Attachment in Excel

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

KENTUCKY UTILITIES COMPANY

CASE NO. 2014-00371

Response to Second Set of Data Requests of
Kentucky Industrial Utility Customers, Inc.
Dated February 6, 2015

Question No. 2-10

Responding Witness: Christopher M. Garrett

Q.2-10. Refer to the Company's response to KIUC 1-36 regarding property tax expense.

a. Please indicate if the Company allocates the property taxes assessed between expense and capital for accounting purposes, i.e., capitalizes the property tax expense related to CWIP. If the Company does not do so, then please explain why it does not.

b. Please indicate if the accumulated depreciation amounts used in the Company's calculation of property tax expense include the net negative salvage reflected in depreciation expense. If not, then please explain why net negative salvage was excluded for that purpose.

A.2-10. a. Per the Company's accounting policy, 656 - Capitalized Property Taxes, only property taxes on CWIP that relate to the original construction costs of coal-fired generating units are capitalized. All other property taxes on construction costs are expensed. There were no original construction costs of coal-fired generating units in the base year, therefore, no property taxes were capitalized.

b. Yes, the accumulated depreciation amounts include the net negative salvage reflected in depreciation expense.

KENTUCKY UTILITIES COMPANY

CASE NO. 2014-00371

Response to Second Set of Data Requests of
Kentucky Industrial Utility Customers, Inc.
Dated February 6, 2015

Question No. 2-11

Responding Witness: John J. Spanos

Q.2-11. Please indicate the terminal net salvage rates included in the depreciation rates by account for each of the Company's generating plants. Please indicate when terminal net salvage was first included in the depreciation rates for each of the plants.

A.2-11. Prior to the last rate case, net salvage was not identified between interim and terminal net salvage. Depreciation practices now include the segregation of net salvage which is based on the estimated interim and terminal retirements and the associated net salvage determined as interim or terminal net salvage. In the last rate case the Commission approved a settlement to include a negative 2% terminal net salvage percent for KU generating plant.

KENTUCKY UTILITIES COMPANY

CASE NO. 2014-00371

Response to Second Set of Data Requests of
Kentucky Industrial Utility Customers, Inc.
Dated February 6, 2015

Question No. 2-12

Responding Witness: John J. Spanos

Q.2-12. Refer to the Company's response to PSC 2-40, which shows the net negative salvage rate applicable to the entirety of the depreciable plant balance.

a. Please confirm that the entirety of the depreciable plant balance consists of both interim retirements and terminal retirements.

b. Please provide the calculations of the net negative salvage rate separated into net negative interim salvage and net negative terminal salvage and the weighting that was used to develop a single net negative salvage rate.

c. Provide this same information for all Cane Run 7 plant accounts.

A.2-12.

a. The attachment to PSC 2-40 represents the weighted net salvage percentage, which includes a component of interim and terminal net salvage associated with the projected assets to be retired based on interim and terminal retirements.

b. The attached document sets forth the calculations of the net negative net salvage percentages for both interim and terminal net salvage with the developed weighting.

c. The calculations for Cane Run Unit 7 were not conducted in the exact same fashion because it was determined not to include a terminal net salvage component in the proposed rates since no plans have been established for how the facility would be dismantled.

KENTUCKY UTILITIES COMPANY

CALCULATION OF WEIGHTED NET SALVAGE PERCENT FOR GENERATION PLANT AS OF DECEMBER 31, 2011

	Terminal Retirements			Interim Retirements			Total		Estimated
Account	Retirements ($)	Net Salvage (%)	Net Salvage ($)	Retirements ($)	Net Salvage (%)	Net Salvage ($)	Net Salvage ($)	Total Retirements	Net Salvage (%)
(1)	(2)	(3)	(4)=(2)x(3)	(5)	(6)	(7)=(5)x(6)	(8)=(4)+(7)	(9)=(2)+(5)	(10)=(8)/(9)
STEAM PRODUCTION PLANT									
BROWN GENERATING STATION									
311 STRUCTURES AND IMPROVEMENTS	68,849,852	(2)	(1,273,722)	3,042,333	(25)	760,583	2,034,305	71,892,185	(4)
312 BOILER PLANT EQUIPMENT	509,778,912	(2)	(9,430,910)	43,833,934	(30)	13,150,180	22,581,090	553,612,846	(4)
314 TURBOGENERATOR UNITS	34,988,354	(2)	(647,285)	14,117,591	(15)	2,117,639	2,764,923	49,105,945	(4)
315 ACCESSORY ELECTRIC EQUIPMENT	41,743,969	(2)	(772,263)	2,382,005	(20)	476,401	1,248,664	44,125,974	(4)
316 MISCELLANEOUS POWER PLANT EQUIPMENT	4,844,375	(2)	(89,621)	765,310	0	-	89,621	5,609,684	(4)
TOTAL BROWN GENERATING STATION	*560,205,462*		*(12,213,801)*	*64,141,173*		*16,504,803*	*28,718,604*	*724,346,634*	*(4)*
GHENT GENERATING STATION									
311 STRUCTURES AND IMPROVEMENTS	120,501,240	(2)	(2,229,273)	11,852,267	(25)	2,963,067	5,192,340	132,353,507	(5)
312 BOILER PLANT EQUIPMENT	1,321,271,054	(2)	(24,443,515)	171,355,455	(30)	51,406,637	75,850,151	1,492,626,510	(5)
314 TURBOGENERATOR UNITS	111,677,673	(2)	(2,066,037)	55,059,770	(15)	8,258,966	10,325,002	166,737,443	(5)
315 ACCESSORY ELECTRIC EQUIPMENT	94,779,021	(2)	(1,753,412)	13,632,245	(20)	2,726,449	4,479,861	108,411,266	(5)
316 MISCELLANEOUS POWER PLANT EQUIPMENT	12,430,337	(2)	(229,961)	2,456,361	0	-	229,961	14,886,698	(5)
TOTAL GHENT GENERATING STATION	*1,660,659,326*		*(30,722,198)*	*254,356,098*		*65,355,118*	*96,077,315*	*1,915,015,424*	*(5)*
GREEN RIVER GENERATING STATION									
311 STRUCTURES AND IMPROVEMENTS	10,698,728	(2)	(197,926)	159,527	(25)	39,882	237,808	10,858,255	(2)
312 BOILER PLANT EQUIPMENT	36,914,230	(2)	(682,913)	746,752	(30)	224,026	906,939	37,660,983	(2)
314 TURBOGENERATOR UNITS	14,317,850	(2)	(264,880)	634,829	(15)	95,224	360,105	14,952,679	(2)
315 ACCESSORY ELECTRIC EQUIPMENT	3,785,377	(2)	(70,029)	115,314	(20)	23,063	93,092	3,900,691	(2)
316 MISCELLANEOUS POWER PLANT EQUIPMENT	2,606,735	(2)	(48,225)	38,304	0	-	48,225	2,645,039	(2)
TOTAL GREEN RIVER GENERATING STATION	*68,322,920*		*(1,263,974)*	*1,694,727*		*382,195*	*1,646,169*	*70,017,647*	*(2)*
PINEVILLE GENERATING STATION									
311 STRUCTURES AND IMPROVEMENTS	16,195	(2)	(300)	9	(25)	2	302	16,204	(2)
312 BOILER PLANT EQUIPMENT	232,704	(2)	(4,305)	3,766	(30)	1,130	5,435	236,470	(2)
314 TURBOGENERATOR UNITS	-	(2)	0	-	(15)	-	-	-	(2)
315 ACCESSORY ELECTRIC EQUIPMENT	-	(2)	0	-	(20)	-	-	-	(2)
316 MISCELLANEOUS POWER PLANT EQUIPMENT	-	(2)	0	-	0	-	-	-	(2)
TOTAL PINEVILLE GENERATING STATION	*248,900*		*(4,605)*	*3,775*		*1,132*	*5,737*	*252,675*	*(2)*
SYSTEM LAB									
311 STRUCTURES AND IMPROVEMENTS	744,220	0	0	80,748	(25)	20,187	20,187	824,969	(1)
312 BOILER PLANT EQUIPMENT	-	0	0	-	(30)	-	-	-	(1)
314 TURBOGENERATOR UNITS	-	0	0	-	(15)	-	-	-	(1)
315 ACCESSORY ELECTRIC EQUIPMENT	-	0	0	-	(20)	-	-	-	(1)
316 MISCELLANEOUS POWER PLANT EQUIPMENT	2,394,972	0	0	368,077	0	-	-	2,763,049	(1)
TOTAL SYSTEM LAB	*3,139,193*		-	*448,825*		*20,187*	*20,187*	*3,588,017*	*(1)*
STEAM PRODUCTION PLANT (CONT.)									
TYRONE GENERATING STATION									
311 STRUCTURES AND IMPROVEMENTS	6,066,662	(2)	(112,233)	125,545	(25)	31,386	143,619	6,192,207	(3)
312 BOILER PLANT EQUIPMENT	14,040,352	(2)	(259,747)	374,833	(30)	112,450	372,197	14,415,186	(3)
314 TURBOGENERATOR UNITS	4,588,909	(2)	(84,895)	284,811	(15)	42,722	127,616	4,873,719	(3)
315 ACCESSORY ELECTRIC EQUIPMENT	2,110,076	(2)	(39,036)	70,827	(20)	14,165	53,202	2,180,903	(3)
316 MISCELLANEOUS POWER PLANT EQUIPMENT	592,490	(2)	(10,961)	10,992	0	-	10,961	603,482	(3)
TOTAL TYRONE GENERATING STATION	*27,398,488*		*(506,872)*	*867,009*		*200,723*	*707,595*	*28,265,497*	*(3)*
TRIMBLE COUNTY									
311 STRUCTURES AND IMPROVEMENTS	86,202,297	(2)	(1,594,742)	25,610,591	(25)	6,402,648	7,997,390	111,812,888	(11)
312 BOILER PLANT EQUIPMENT	352,937,892	(2)	(6,529,351)	222,956,396	(30)	66,886,919	73,416,270	575,894,288	(11)
314 TURBOGENERATOR UNITS	31,029,751	(2)	(574,050)	52,964,982	(15)	7,944,747	8,518,798	83,994,733	(11)
315 ACCESSORY ELECTRIC EQUIPMENT	26,315,352	(2)	(486,834)	16,700,474	(20)	3,340,095	3,826,929	43,015,826	(11)
316 MISCELLANEOUS POWER PLANT EQUIPMENT	2,298,460	(2)	(42,522)	1,203,987	0	-	42,522	3,502,447	(11)
TOTAL TRIMBLE COUNTY	*498,783,752*		*(9,227,499)*	*319,436,430*		*84,574,409*	*93,801,908*	*818,220,182*	*(11)*
TOTAL STEAM PRODUCTION PLANT	2,918,758,040		(53,938,949)	640,948,036		167,038,567	220,977,515	3,559,706,076	

KENTUCKY UTILITIES COMPANY

CALCULATION OF WEIGHTED NET SALVAGE PERCENT FOR GENERATION PLANT AS OF DECEMBER 31, 2011

		Terminal Retirements			Interim Retirements			Total		Estimated
	Account	Retirements ($)	Net Salvage (%)	Net Salvage ($)	Retirements ($)	Net Salvage (%)	Net Salvage ($)	Net Salvage ($)	Total Retirements	Net Salvage (%)
	(1)	(2)	(3)	(4)=(2)x(3)	(5)	(6)	(7)=(5)x(6)	(8)=(4)+(7)	(9)=(2)+(5)	(10)=(8)/(9)
	HYDRAULIC PRODUCTION PLANT									
	DIX DAM									
331	STRUCTURES AND IMPROVEMENTS	460,238	(2)	(8,514)	156,289	(5)	7,814	16,329	616,527	(3)
332	RESERVOIRS, DAMS AND WATERWAYS	19,039,829	(2)	(352,237)	2,564,141	(10)	256,414	608,651	21,603,970	(3)
333	WATER WHEELS, TURBINES AND GENERATORS	4,076,011	(2)	(75,406)	354,613	(20)	70,923	146,329	4,430,624	(3)
334	ACCESSORY ELECTRIC EQUIPMENT	355,642	(2)	(6,579)	222,692	0	-	6,579	578,333	(3)
335	MISCELLANEOUS POWER PLANT EQUIPMENT	77,245	(2)	(1,429)	219,779	(5)	10,989	12,418	297,024	(3)
336	ROADS, RAILROADS AND BRIDGES	124,770	(2)	(2,308)	51,589	0	-	2,308	176,360	(3)
	TOTAL DIX DAM	*24,133,734*		*(446,474)*	*3,569,103*		*346,140*	*792,614*	*27,702,837*	*(3)*
	TOTAL HYDRAULIC PRODUCTION PLANT	24,133,734		(446,474)	3,569,103		346,140	792,614	27,702,837	
	OTHER PRODUCTION PLANT									
	BROWN CTS									
341	STRUCTURES AND IMPROVEMENTS	9,195,757	(2)	(170,122)	2,731,546	0	-	170,122	11,927,303	(2)
342	FUEL HOLDERS, PRODUCERS AND ACCESSORIES	10,211,547	(2)	(188,914)	2,322,415	(5)	116,121	305,034	12,533,962	(2)
343	PRIME MOVERS	136,839,902	(2)	(2,531,538)	49,000,992	(5)	2,450,050	4,981,588	185,840,895	(2)
344	GENERATORS	29,442,983	(2)	(544,695)	1,388,038	(5)	69,402	614,097	30,831,020	(2)
345	ACCESSORY ELECTRIC EQUIPMENT	15,263,350	(2)	(282,372)	2,458,791	(5)	122,940	405,312	17,722,142	(2)
346	MISCELLANEOUS POWER PLANT EQUIPMENT	2,938,221	(2)	(54,357)	1,201,669	0	-	54,357	4,139,890	(2)
	TOTAL BROWN CTS	*203,891,761*		*(3,771,998)*	*59,103,452*		*2,758,512*	*6,530,509*	*262,995,213*	*(2)*
	HAEFLING CTS									
341	STRUCTURES AND IMPROVEMENTS	412,940	(2)	(7,639)	21,913	0	-	7,639	434,853	(2)
342	FUEL HOLDERS, PRODUCERS AND ACCESSORIES	479,905	(2)	(8,878)	38,800	(5)	1,940	10,818	518,705	(2)
344	GENERATORS	3,223,465	(2)	(59,634)	799,537	(5)	39,977	99,611	4,023,002	(2)
345	ACCESSORY ELECTRIC EQUIPMENT	1,211,240	(2)	(22,408)	240,717	(5)	12,036	34,444	1,451,957	(2)
346	MISCELLANEOUS POWER PLANT EQUIPMENT	13,500	(2)	(250)	22,305	0	-	250	35,805	(2)
	TOTAL HAEFLING CTS	*5,341,050*		*(98,809)*	*1,123,272*		*53,953*	*152,762*	*6,464,323*	*(2)*
	PADDY'S RUN CTS									
341	STRUCTURES AND IMPROVEMENTS	1,563,219	(2)	(28,920)	347,109	0	-	28,920	1,910,328	(2)
342	FUEL HOLDERS, PRODUCERS AND ACCESSORIES	1,730,245	(2)	(32,010)	264,856	(5)	13,243	45,252	1,995,101	(2)
343	PRIME MOVERS	12,869,763	(2)	(238,091)	4,933,601	(5)	246,680	484,771	17,803,364	(2)
344	GENERATORS	5,045,282	(2)	(93,338)	140,354	(5)	7,018	100,355	5,185,636	(2)
345	ACCESSORY ELECTRIC EQUIPMENT	2,184,168	(2)	(40,407)	272,152	(5)	13,608	54,015	2,456,320	(2)
346	MISCELLANEOUS POWER PLANT EQUIPMENT	784,628	(2)	(14,516)	304,922	0	-	14,516	1,089,550	(2)
	TOTAL PADDY'S RUN CTS	*24,177,306*		*(447,280)*	*6,262,993*		*280,548*	*727,828*	*30,440,299*	*(2)*
	TRIMBLE COUNTY CTS									
341	STRUCTURES AND IMPROVEMENTS	17,661,338	(2)	(326,735)	4,084,591	0	-	326,735	21,745,929	(3)
342	FUEL HOLDERS, PRODUCERS AND ACCESSORIES	6,528,160	(2)	(120,771)	1,171,888	(5)	58,594	179,365	7,700,048	(3)
343	PRIME MOVERS	109,263,693	(2)	(2,021,378)	45,915,081	(5)	2,295,754	4,317,132	155,178,774	(3)
344	GENERATORS	18,798,072	(2)	(347,764)	523,030	(5)	26,152	373,916	19,321,102	(3)
345	ACCESSORY ELECTRIC EQUIPMENT	20,149,294	(2)	(372,762)	2,587,693	(5)	129,385	502,147	22,736,987	(3)
346	MISCELLANEOUS POWER PLANT EQUIPMENT	75,076	(2)	(1,389)	22,620	0	-	1,389	97,696	(3)
	TOTAL TRIMBLE COUNTY CTS	*172,475,634*		*(3,190,799)*	*54,304,902*		*2,509,885*	*5,700,684*	*226,780,536*	*(3)*
	TOTAL OTHER PRODUCTION PLANT	405,885,751		(7,508,886)	120,794,620		5,602,897	13,111,784	526,680,370	
	GRAND TOTAL	3,348,777,525		(61,894,309)	765,311,759		172,987,604	234,881,913	4,114,089,284	

KENTUCKY UTILITIES COMPANY

CASE NO. 2014-00371

Response to Second Set of Data Requests of
Kentucky Industrial Utility Customers, Inc.
Dated February 6, 2015

Question No. 2-13

Responding Witness: John J. Spanos

Q.2-13. Refer to the Company's response to PSC 2-41, which states that there is no terminal salvage included in the Cane Run 7 depreciation rates.

a. Please separate the Cane Run 7 depreciable plant balance into interim retirements and terminal retirements.

b. Please confirm that the proposed Cane Run 7 net negative salvage rate was applied to the entirety of the depreciable plant balance, including the portion expected to survive to terminal retirement.

A.2-13.

a. The attached document sets forth the projected assets as of April 30, 2015 which will be retired on an interim and terminal basis.

b. For purposes of establishing the projected depreciation rates in this case, the net salvage percentages were applied to the entire depreciable plant balance as of April 30, 2015.

KENTUCKY UTILITIES COMPANY
CANE RUN 7

PROJECTED INTERIM AND TERMINAL RETIREMENTS BASED ON
APRIL 30, 2015

	ACCOUNT	SURVIVOR CURVE	RETIREMENT DATE	ORIGINAL COST	INTERIM RETIREMENTS	TERMINAL RETIREMENTS
	(1)	(2)	(3)	(4)	(5)	(6)
341	STRUCTURES AND IMPROVEMENTS	60-S1.5	6-2055	67,731,300.00	(12,108,915.70)	(55,622,384.30)
342	FUEL HOLDERS, PRODUCERS AND ACCESSORIES	55-R3	6-2055	31,607,940.00	(4,955,060.20)	(26,652,879.80)
343	PRIME MOVERS	55-R2.5	6-2055	103,854,660.00	(19,607,326.16)	(84,247,333.84)
344	GENERATORS	50-R1.5	6-2055	203,193,900.00	(60,611,508.93)	(142,582,391.07)
345	ACCESSORY ELECTRIC EQUIPMENT	50-S0.5	6-2055	36,123,360.00	(12,098,829.55)	(24,024,530.45)
346	MISCELLANEOUS POWER PLANT EQUIPMENT	45-R2	6-2055	9,030,840.00	(3,093,422.56)	(5,937,417.44)
	TOTAL OTHER PRODUCTION PLANT			451,542,000.00	(112,475,063.10)	(339,066,936.90)

KENTUCKY UTILITIES COMPANY

CASE NO. 2014-00371

Response to Second Set of Data Requests of Kentucky Industrial Utility Customers, Inc. Dated February 6, 2015

Question No. 2-14

Responding Witness: Kent W. Blake / Paula H. Pottinger, Ph.D. / Counsel

Q.2-14. Refer to the Company's response to KIUC 1-12. The question asked the following:

Please provide the incentive compensation expense for 2013, 2014, the base year, and the test year by incentive compensation plan and by goal or target for each plan. This includes incentive compensation expense assigned and allocated to the Company as well as incentive compensation expense incurred directly by the Company.

The Company's response referred to its response to AG 1-150. The response to AG 1-150 does not provide the information requested in KIUC 1-12 by plan and by goal or target for each plan. It also does not provide the information for LKS charged to the Company.

a. Please provide the information requested in KIUC 1-12. To be clear, this request also includes all stock-based compensation awards, and is not limited only to incentive compensation with cash or deferred payouts.

b. Please provide the calculation of incentive compensation expense in the historic year, the base year and the test year in electronic format with all formulas intact. This calculation should reflect all performance metrics and goals, the achieved metric or goal, and the calculation of the cost, including the allocation between expense and capital.

A.2-14. a. See the Company's Objection filed on February 16, 2015. The Team Incentive Award (TIA) is the only plan with payments included in the cost of service. Information by goal and by target for the TIA is provided in response to AG 1-76. None of the costs of stock-based compensation or other incentive plans, beyond the TIA, were incurred by Kentucky Utilities Company, nor were any such costs allocated to Kentucky Utilities Company by any other entity.

b. The attached information is from the Company's financial system and provides incentive compensation expense for 2013, 2014, the base year and the test year. Incentive compensation expense is determined at the beginning of the year, reviewed quarterly and adjusted, if appropriate. Incentive compensation expense is based on labor allocations from the Company's financial system and assumes on-target financial, customer satisfaction and team performance. Individual performance is assumed at 120%. When actual incentive payouts are made during the first quarter of the following year, true-up entries are made to allocate the incentive expense to the appropriate companies and FERC accounts.

While the Company does not report incentive expense by performance goal, 2013's expense is provided below by financial, customer, individual and team performance goals. 2014 incentive expense by performance goal will be available mid-March. See the response to AG 1-76 for details on measure weightings.

Performance Measure	Capitalized	Expensed	Other Balance Sheet	Total
Financial - PPL EPS	30,600	128,213	16,755	175,568
Financial - LKE Net Income	1,514,625	6,346,183	829,312	8,690,120
Customer Satisfaction	352,541	1,477,125	193,029	2,022,696
Individual/Team Effectiveness	739,397	3,098,026	404,847	4,242,269
Total	2,637,163	11,049,547	1,443,943	15,130,652

Kentucky Utilities
Case No. 2014-00371
Incentive Compensation Expense for 2013, 2014, Base Year and Test Year

Company Allocated from	KU Capitalized	Expensed	Other Balance Sheet	Total
2013				
Servco	932,862	6,224,626	558,715	7,716,203
LGE	72,010	590,166	4,098	666,274
KU	1,632,290	4,234,754	881,130	6,748,175
	2,637,163	11,049,547	1,443,943	15,130,652
2014				
Servco	897,388	6,707,097	638,069	8,242,553
LGE	136,308	662,181	1,997	800,487
KU	1,531,086	3,921,890	939,384	6,392,360
	2,564,782	11,291,168	1,579,450	15,435,400
Base Period				
Servco	638,433	6,013,104	486,415	7,137,953
LGE	57,100	348,698	2,565	408,363
KU	1,485,327	4,294,301	392,326	6,171,954
	2,180,860	10,656,104	881,306	13,718,270
Forecasted Test Period				
Servco	764,253	6,523,127	629,908	7,917,288
LGE	9,117	27,117	-	36,234
KU	1,326,217	4,423,194	304,422	6,053,834
	2,099,587	10,973,438	934,331	14,007,355

KENTUCKY UTILITIES COMPANY

CASE NO. 2014-00371

Response to Second Set of Data Requests of
Kentucky Industrial Utility Customers, Inc.
Dated February 6, 2015

Question No. 2-15

Responding Witness: Russel A. Hudson

Q.2-15. Refer to the Company's response to AG 1-150.

a. Please explain why the overtime payroll expense in the test year increased by more than $2 million for each Company even while each Company proposes significantly increased staffing levels. This relationship would appear to be counterintuitive.

b. Please provide the calculation of overtime expense for the historic year, the base year and the test year.

A.2-15. a. Overtime included in the test year Expense is $11,316,011. This amount is lower than the average overtime for the preceding six years included in AG 1-150, which is an average of $12,048,941. The overtime in the base period is lower due to how labor is forecasted on a monthly basis. Labor for the forecasted months in the base period is recorded in total, not between straight time and overtime. The amounts shown in AG 1-150 have the total adjustments included in Base Pay. See attached.

b. See attached.

Kentucky Utilities Company
Case No. 2014-00371
Overtime/Other Pay

		Expensed	Capitalized	Other Balance	Total
Overtime/Other Pay					
	2009	$ 14,001,157	$ 2,979,159	$ 117,394	$ 17,097,710
	2010	9,567,626	2,474,827	529,701	12,572,154
	2011	11,382,298	2,320,728	1,547,780	15,250,806
	2012	12,544,769	2,534,337	1,879,206	16,958,312
	2013	11,207,187	3,041,949	368,549	14,617,685
	2014	13,590,608	3,270,728	684,241	17,545,577
Six year Average overtime		12,048,941	2,770,288	854,479	15,673,707
Base Period		9,026,998	2,316,115	203,078	11,546,191
Test Period		11,316,011	1,481,420	11,441	12,808,872
Change from Base to Test		(2,289,013)	834,695	191,637	(1,262,681)
Change from Historical Average to Test		732,930	1,288,868	843,038	2,864,835

Kentucky Utilities Company
Case No. 2014-00371
Overtime Expense Calculation

Period	Type of Cost		Expensed	Capitalized	Other Balance Sheet	Total
2014	Overtime		10,951,400	2,489,640	373,468	13,814,508
2014	Doubletime		1,964,792	709,001	280,005	2,953,798
2014	Other Pay		674,416	72,087	30,768	777,271
		Total	$ 13,590,608	$ 3,270,728	$ 684,241	$ 17,545,577
Base Period	Overtime		9,210,388	1,912,492	146,878	11,269,758
Base Period	Doubletime		(217,394)	366,370	49,274	198,250
Base Period	Other Pay		34,004	37,253	6,926	78,183
		Total	9,026,998	2,316,115	203,078	11,546,191
Forecasted TY	Overtime		9,483,911	1,481,420	11,441	10,976,772
Forecasted TY	Doubletime		-	-	-	-
Forecasted TY	Other Pay		1,832,100	-	-	1,832,100
		Total	$ 11,316,011	$ 1,481,420	$ 11,441	$ 12,808,872

KENTUCKY UTILITIES COMPANY

CASE NO. 2014-00371

Response to Second Set of Data Requests of
Kentucky Industrial Utility Customers, Inc.
Dated February 6, 2015

Question No. 2-16

Responding Witness: Kent W. Blake / Paula H. Pottinger, Ph.D.

Q.2-16. Refer to the Company's response to AG 1-75, which sought complete copies of any incentive compensation plan, bonus program or other incentive award program in effect at the Company for each year 2010 through 2014. In its response, the Company provided a single document describing the Team Incentive Award Plan. Based on the PPL Proxy Statement for 2014, it appears that there are other incentive compensation plans applicable to executive and other management positions.

a. Please confirm that the Team Incentive Award Plan is the only incentive compensation, bonus program or other incentive award program in effect in any of those years that was included in operating expense on the Company's accounting books. If this is not correct, then please supplement the response to AG 1-75.

b. Please provide the amount of incentive compensation expense recorded by O&M and A&G expense account by plan and by performance metric for each plan in 2012, 2013, 2014, the base year and the test year. Provide this amount for each utility, showing separately amounts incurred by LKE and/or PPL that were charged to each utility.

A.2-16. a. The Team Incentive Award Plan is the only incentive compensation, bonus program or other incentive award program in effect for 2010 through 2014 that was included in operating expense on the Company's accounting books.

b. Detailed incentive compensation by originating company and by O&M and A&G accounts are included in the attachment for historical years 2012-2014. The allocation process for the budget combines the incentive compensation with other labor-related cost allocations. Therefore, the detailed level of data is not available. See the response to Question No. 2-14 for incentive compensation by originating company and account type for the base and test years.

Kentucky Utilities
Case No. 2014-00371
Incentive Compensation Charged to A&G, O&M and Expense by Account for 2012, 2013 , and 2014

	2012	2013	2014
From Servco	4,807,767	6,224,626	6,707,097
A&G			
901001 - SUPV-CUST ACCTS	141,128	213,855	45,751
901900 - SUPV-CUST ACCTS - INDIRECT	24,530	38,337	231,446
902001 - METER READ-SERV AREA	14,257	11,273	2,492
902900 - METER READ-SERV AREA - INDIRECT		6,186	12,214
903001 - AUDIT CUST ACCTS	67,204	88,254	31
903003 - PROCESS METER ORDERS		86	45
903006 - CUST BILL/ACCTG	2,095	3,934	-
903007 - PROCESS PAYMENTS		2,192	483
903008 - INVEST THEFT OF SVC			675
903012 - PROC CUST CNTRT/ORDR	6,348	5,647	5,580
903022 - COLL OFF-LINE BILLS	53,411	48,140	32,871
903030 - PROC CUST REQUESTS	3,143	2,885	2,874
903031 - PROC CUST PAYMENTS	5,956	10,650	-
903035 - COLLECTING-OTHER	2,765	14,408	4,919
903036 - CUSTOMER COMPLAINTS	15,935	14,474	15,632
903901 - AUDIT CUST ACCTS - INDIRECT			2,272
903902 - BILL SPECIAL ACCTS - INDIRECT	3,209	4,648	6,322
903906 - CUST BILL/ACCTG - INDIRECT	28,638	40,819	168,802
903907 - PROCESS PAYMENTS - INDIRECT	810	944	326
903908 - INVESTIGATE THEFT OF SERVICE - INDIRECT			7,954
903912 - PROC CUST CNTRT/ORDR - INDIRECT	28,397	22,448	24,178
903922 - COLLECT OFF-LINE BILLS - INDIRECT			1,711
903930 - PROC CUST REQUESTS - INDIRECT	306,965	438,112	464,368
903931 - PROC CUST PAYMENTS - INDIRECT	3,633	2,870	19,925
903935 - COLLECTING-OTHER - INDIRECT			1,439
903936 - CUSTOMER COMPLAINTS - INDIRECT	12,928	17,295	22,222
905001 - MISC CUST SERV EXP	25,096	380	-
905002 - MISC CUST BILL/ACCTG	10,657	10,723	(0)
905900 - MISC CUST SERV EXP - INDIRECT			119
907001 - SUPV-CUST SER/INFO	2,819	1,959	
907900 - SUPV-CUST SER/INFO - INDIRECT	15,132	25,586	32,529
908005 - DSM CONSERVATION PROG	79,793	94,304	86,728
908901 - CUST MKTG/ASSIST - INDIRECT	20,701	23,458	23,748
920100 - OTHER GENERAL AND ADMIN SALARIES	197,982	183,729	150,924
920900 - OTHER GENERAL AND ADMIN SALARIES - INDIRECT	1,877,929	2,780,962	3,402,466
925004 - SAFETY AND INDUSTRIAL HEALTH	4,275	2,739	
930274 - RESEARCH AND DEVELOPMENT EXPENSES - INDIRECT	12,872	26,070	23,555
935391 - MTCE-COMMUNICATION EQ - INDIRECT	47,345	31,019	
935401 - MTCE-OTH GEN EQ	654	259	
935402 - MAINT. OF NON-BONDABLE GENERAL PLANT	22		
935403 - MNTC BONDABLE PROPERTY	74		184
935488 - MTCE-OTH GEN EQ - INDIRECT	422,645	294,504	17,114
O&M			
500100 - OPER SUPER/ENG	14,437	16,661	20,011
500900 - OPER SUPER/ENG - INDIRECT	243,636	369,021	439,168
501090 - FUEL HANDLING	41,405	44,111	31,553

Kentucky Utilities
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Incentive Compensation Charged to A&G, O&M and Expense by Account for 2012, 2013 , and 2014

	2012	2013	2014
501990 - FUEL HANDLING - INDIRECT	62,213	82,275	89,721
502002 - BOILER SYSTEMS OPR		8	
502004 - SDRS-H2O SYS OPR		7	
502100 - STM EXP(EX SDRS.SPP)	8,405	9,761	8,584
505100 - ELECTRIC SYS OPR		52	
506100 - MISC STM PWR EXP	91	61	44
506109 - SORBENT INJECTION OPERATION		110	
506110 - MERCURY MONITORS OPERATIONS			1,415
506900 - MISC STM PWR EXP - INDIRECT			3,119
510100 - MTCE SUPER/ENG - STEAM	63,199	16,259	846
510900 - MTCE SUPER/ENG - STEAM - INDIRECT		17,970	14,601
511100 - MTCE-STRUCTURES	105	49	67
512005 - MAINTENANCE-SDRS	9	4	
512011 - INSTR/CNTRL-ENVRNL	223		
512017 - MTCE-SLUDGE STAB SYS		19	14
512100 - MTCE-BOILER PLANT		501	1,981
513100 - MTCE-ELECTRIC PLANT	5,144	666	10,120
513900 - MTCE-ELECTRIC PLANT - BOILER	4,624	8,108	5,191
514100 - MTCE-MISC/STM PLANT	164	328	
553100 - DO NOT USE -- MTCE-GEN/ELECT EQ		38	
556100 - SYS CTRL / DISPATCHING	6,481	9,494	8,975
556900 - SYS CTRL / DISPATCHING - INDIRECT	143,913	153,464	156,388
557999 - KU PLANT ALLOCATION CLEARING ACCOUNT	-	-	-
560100 - OP SUPER/ENG-SSTOPER	2,738	2,437	55
560900 - OP SUPER/ENG-SSTOPER - INDIRECT	120,812	173,423	157,743
561100 - LOAD DISPATCH-WELOB	39		
561190 - LOAD DISPATCH - INDIRECT	175,206	224,906	164,915
561201 - LOAD DISPATCH-MONITOR AND OPERATE TRANSMISSION SYSTEM			17,724
561291 - LOAD DISPATCH-MONITOR AND OPERATE TRANSMISSION SYSTEM - INDIRECT			14,047
561391 - LOAD DISPATCH-TRANSMISSION SERVICE AND SCHEDULING - INDIRECT			19,229
561590 - RELIABILITY, PLANNING AND STANDARDS DEVELOPMENT - INDIRECT	67,258	90,483	76,756
561601 - TRANSMISSION SERVICE STUDIES	373	1,134	1,718
561900 - CLOSED 01/15 - LOAD DISPATCH-WELOB - INDIRECT	(2,056)	10,138	15,301
562100 - DO NOT USE -- STA EXP-SUBST OPER	1,633	482	2,164
563100 - OTHER INSP-ELEC TRAN	7,018	5,664	4,197
566100 - MISC TRANS EXP-SSTMT	4,184	4,100	3,925
566900 - MISC TRANS EXP-SSTMT - INDIRECT	6,688	10,011	7,298
570100 - DO NOT USE -- MTCE-ST EQ-SSTMTCE	24,275	33,701	44,877
570900 - MTCE-ST EQ-SSTMTCE - INDIRECT		5,077	12,131
571100 - MTCE OF OVERHEAD LINES	13,065	8,400	8,550
573100 - MTCE-MISC TR PLT-SSTMT	6,550	3,243	1,593
573900 - MTCE-MISC TR PLT-SSTMT INDIRECT		1,511	6,630
580100 - OP SUPER/ENG-SSTOPER	77,373	46,876	10,350
580900 - OP SUPER/ENG-SSTOPER - INDIRECT	16,161	46,042	72,127
581100 - SYS CTRL/SWITCH-DIST			2,652
581900 - SYS CTRL/SWITCH-DIST - INDIRECT	81,758	95,636	77,254
582100 - STATION EXP-SSTOPER	(50)	1,592	2,745
583001 - OPR-O/H LINES		232	1,504
583005 - CUST COMPL RESP-O/H		48,193	114,098

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Incentive Compensation Charged to A&G, O&M and Expense by Account for 2012, 2013 , and 2014

	2012	2013	2014
586100 - METER EXP	50,282	57,338	9,446
586900 - METER EXP - INDIRECT		863	36,383
588100 - MISC DIST EXP-SUBSTATION OPERATIONS	42,596	33,958	23,495
588900 - MISC DIST EXP-SUBSTATION OPERATIONS - INDIRECT	14,653	44,632	113,532
590100 - MTCE/SUPER/ENG-SSTMT	434	427	110
590900 - MTCE/SUPER/ENG-SSTMT - INDIRECT		239	934
592100 - MTCE-ST EQ-SSTMTCE	61	79	780
593001 - MTCE-POLE/FIXT-DISTR		43	124
593002 - MTCE-COND/DEVICE-DIS	101	950	2,503
593003 - MTCE-SERVICES			212
593004 - TREE TRIMMING	7,717	9,616	183
593904 - TREE TRIMMING - INDIRECT			11,774
594001 - MTCE-ELEC MANHOL ETC		38	
594002 - MTCE-U/G COND ETC			33
598100 - MTCE OF MISC DISTRIBUTION PLANT	830	626	898
Oth IS			
426401 - EXP-CIVIC/POL/REL	40	46	516
426491 - EXP-CIVIC/POL/REL - INDIRECT	52,081	65,576	58,814
426501 - OTHER DEDUCTIONS	1,862	4,239	1,618
426591 - OTHER DEDUCTIONS - INDIRECT	686	563	2,462
From LGE	500,234	590,166	662,181
A&G			
901900 - SUPV-CUST ACCTS - INDIRECT		19	15
902900 - METER READ-SERV AREA - INDIRECT			1
903001 - AUDIT CUST ACCTS		2	
903003 - PROCESS METER ORDERS		22	(1)
903006 - CUST BILL/ACCTG	1		
903901 - AUDIT CUST ACCTS - INDIRECT			4
903906 - CUST BILL/ACCTG - INDIRECT			10
903907 - PROCESS PAYMENTS - INDIRECT			620
903908 - INVESTIGATE THEFT OF SERVICE - INDIRECT			1
903912 - PROC CUST CNTRT/ORDR - INDIRECT		2	116
903930 - PROC CUST REQUESTS - INDIRECT	25	250	1,390
905001 - MISC CUST SERV EXP	1	38	
907900 - SUPV-CUST SER/INFO - INDIRECT			8
908005 - DSM CONSERVATION PROG	18	13	
908901 - CUST MKTG/ASSIST - INDIRECT			4
920100 - OTHER GENERAL AND ADMIN SALARIES	3	14	6
920900 - OTHER GENERAL AND ADMIN SALARIES - INDIRECT	373	2,811	1,408
921903 - GEN OFFICE SUPPL/EXP - INDIRECT			-
925004 - SAFETY AND INDUSTRIAL HEALTH	1,803	2,416	3,423
935191 - MTCE-GEN PLANT - INDIRECT			-
935391 - MTCE-COMMUNICATION EQ - INDIRECT	20,482	26,652	4,747
935488 - MTCE-OTH GEN EQ - INDIRECT	20		18,702
O&M			
500100 - OPER SUPER/ENG	42,906	60,474	94,920
500900 - OPER SUPER/ENG - INDIRECT	104	266	23,232
501090 - FUEL HANDLING	22,785	26,109	27,486
501990 - FUEL HANDLING - INDIRECT	1	1	6,675

Kentucky Utilities
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Incentive Compensation Charged to A&G, O&M and Expense by Account for 2012, 2013 , and 2014

	2012	2013	2014
502002 - BOILER SYSTEMS OPR	21,405	27,599	35,561
502004 - SDRS-H2O SYS OPR	6,224	5,869	7,166
502100 - STM EXP(EX SDRS.SPP)	63,125	67,764	67,025
505100 - ELECTRIC SYS OPR	68,904	77,133	76,963
506001 - STEAM OPERATION-AIR QUALITY MONITORING AND CONTROL EQUIPMENT	8,085	9,928	11,656
506100 - MISC STM PWR EXP	24,608	44,488	34,330
506105 - OPERATION OF SCR/NOX REDUCTION EQUIP	4,240	3,188	2,802
506110 - MERCURY MONITORS OPERATIONS			112
506900 - MISC STM PWR EXP - INDIRECT	4	2	173
510100 - MTCE SUPER/ENG - STEAM	21,921	26,974	34,909
510900 - MTCE SUPER/ENG - STEAM - INDIRECT			1,147
511100 - MTCE-STRUCTURES	2,523	2,242	4,307
512005 - MAINTENANCE-SDRS	12,541	22,324	24,622
512011 - INSTR/CNTRL-ENVRNL	148	4,760	4,197
512015 - SDRS-COMMON H2O SYS	5,171	5,799	6,295
512017 - MTCE-SLUDGE STAB SYS	5,142	7,032	4,075
512051 - ECR INSTR/CNTRL-ENVRNL	4,673	162	
512055 - ECR MAINTENANCE-SDRS	8,694	1,388	
512100 - MTCE-BOILER PLANT	75,845	82,964	83,308
512101 - MAINTENANCE OF SCR/NOX REDUCTION EQUIP	26	2,609	2,527
512102 - SORBENT INJECTION MAINTENANCE		1,741	1,908
512151 - ECR MAINTENANCE OF SCR/NOX REDUCTION EQUIP	2,100	551	
512152 - ECR SORBENT INJECTION MAINTENANCE	539		
513100 - MTCE-ELECTRIC PLANT	27,227	24,293	27,288
513900 - MTCE-ELECTRIC PLANT - BOILER		1	973
514100 - MTCE-MISC/STM PLANT	4,057	2,383	4,380
546100 - OPER SUPER/ENG - TURBINES			(1,284)
548100 - DO NOT USE -- GENERATION EXP	20,914	24,161	22,229
549100 - MISC OTH PWR GEN EXP			(54)
551100 - MTCE-SUPER/ENG - TURBINES			(502)
552100 - MTCE-STRUCTURES - OTH PWR	155	133	(1,566)
553100 - DO NOT USE -- MTCE-GEN/ELECT EQ	15,654	19,774	17,091
554100 - MTCE-MISC OTH PWR GEN	70	153	(428)
556900 - SYS CTRL / DISPATCHING - INDIRECT	24	3	
557999 - KU PLANT ALLOCATION CLEARING ACCOUNT	-	-	-
560100 - OP SUPER/ENG-SSTOPER	6	-	
560900 - OP SUPER/ENG-SSTOPER - INDIRECT	13	210	1
561190 - LOAD DISPATCH - INDIRECT	37	53	10
561590 - RELIABILITY, PLANNING AND STANDARDS DEVELOPMENT - INDIRECT	11	16	4
562100 - DO NOT USE -- STA EXP-SUBST OPER	37	-	
566900 - MISC TRANS EXP-SSTMT - INDIRECT			11
570100 - DO NOT USE -- MTCE-ST EQ-SSTMTCE	65	93	2
573100 - MTCE-MISC TR PLT-SSTMT		435	2
580100 - OP SUPER/ENG-SSTOPER	1,609	620	3,782
581900 - SYS CTRL/SWITCH-DIST - INDIRECT		34	
583001 - OPR-O/H LINES	-		
586100 - METER EXP		33	97
586900 - METER EXP - INDIRECT			1
588100 - MISC DIST EXP-SUBSTATION OPERATIONS	653	134	

Kentucky Utilities
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Incentive Compensation Charged to A&G, O&M and Expense by Account for 2012, 2013 , and 2014

	2012	2013	2014
588900 - MISC DIST EXP-SUBSTATION OPERATIONS - INDIRECT		32	27
590900 - MTCE/SUPER/ENG-SSTMT - INDIRECT			2
592100 - MTCE-ST EQ-SSTMTCE	9	120	
593001 - MTCE-POLE/FIXT-DISTR		36	
593002 - MTCE-COND/DEVICE-DIS		872	1,407
593004 - TREE TRIMMING			0
593904 - TREE TRIMMING - INDIRECT			18
595100 - MTCE-TRANSF/REG	4,953	2,932	2,822
598100 - MTCE OF MISC DISTRIBUTION PLANT	286		
Oth IS			
426501 - OTHER DEDUCTIONS	14	39	
426591 - OTHER DEDUCTIONS - INDIRECT	4		21
From KU	3,570,843	4,234,754	3,921,890
A&G			
901001 - SUPV-CUST ACCTS	31,772	38,051	37,956
901900 - SUPV-CUST ACCTS - INDIRECT	113		3
902001 - METER READ-SERV AREA	8,620	10,149	9,939
902002 - METER READ-CLER/OTH			17
903003 - PROCESS METER ORDERS	233,446	284,618	276,169
903007 - PROCESS PAYMENTS			10
903008 - INVEST THEFT OF SVC	3,482	5,641	3,986
903030 - PROC CUST REQUESTS	16,890	18,615	12,496
903906 - CUST BILL/ACCTG - INDIRECT			16
903912 - PROC CUST CNTRT/ORDR - INDIRECT		-	
903930 - PROC CUST REQUESTS - INDIRECT	177	67	44
905001 - MISC CUST SERV EXP	19		
905002 - MISC CUST BILL/ACCTG	993	1,068	
907001 - SUPV-CUST SER/INFO	15		
907900 - SUPV-CUST SER/INFO - INDIRECT			3
908005 - DSM CONSERVATION PROG	242	23	
908909 - MISC MARKETING EXP - INDIRECT		9	-
920100 - OTHER GENERAL AND ADMIN SALARIES	1,858	32,789	(9,246)
920900 - OTHER GENERAL AND ADMIN SALARIES - INDIRECT	1,205	795	393
922001 - A/G SAL TRANSFER-CR	(189,391)	(271,205)	(322,071)
922003 - TRIMBLE CTY TRAN-CR	(30,932)	(32,665)	(48,043)
925001 - PUBLIC LIABILITY		536	
925004 - SAFETY AND INDUSTRIAL HEALTH	222	234	114
930207 - OTHER MISC GEN EXP	99		
935391 - MTCE-COMMUNICATION EQ - INDIRECT	21,463	27,761	6,058
935402 - MAINT. OF NON-BONDABLE GENERAL PLANT	179		
935403 - MNTC BONDABLE PROPERTY	25	18	85
935488 - MTCE-OTH GEN EQ - INDIRECT	8	82	21,982
O&M			
500100 - OPER SUPER/ENG	131,855	158,982	167,060
500900 - OPER SUPER/ENG - INDIRECT	(4,931)	(5,798)	(6,140)
501090 - FUEL HANDLING	139,275	172,214	147,406
501091 - FUEL SAMPLING AND TESTING	338	131	
501990 - FUEL HANDLING - INDIRECT			(1,361)
502001 - OTHER WASTE DISPOSAL	45,964	61,495	33,865

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Incentive Compensation Charged to A&G, O&M and Expense by Account for 2012, 2013 , and 2014

	2012	2013	2014
502002 - BOILER SYSTEMS OPR	367,968	460,346	426,033
502003 - SDRS OPERATION	93,954	117,322	107,128
502004 - SDRS-H2O SYS OPR	40,932	54,024	54,855
502100 - STM EXP(EX SDRS.SPP)	5,032	5,687	33,183
505100 - ELECTRIC SYS OPR	391,782	467,326	433,905
506001 - STEAM OPERATION-AIR QUALITY MONITORING AND CONTROL EQUIPMENT	(493)	(585)	(909)
506100 - MISC STM PWR EXP	65,538	82,139	111,791
506105 - OPERATION OF SCR/NOX REDUCTION EQUIP	(1,060)	(797)	(700)
506109 - SORBENT INJECTION OPERATION		12,405	10,409
506110 - MERCURY MONITORS OPERATIONS			(28)
506900 - MISC STM PWR EXP - INDIRECT	(1)	(1)	(34)
510100 - MTCE SUPER/ENG - STEAM	366,800	422,634	390,049
510900 - MTCE SUPER/ENG - STEAM - INDIRECT		(266)	(275)
511100 - MTCE-STRUCTURES	65,480	82,357	86,445
512005 - MAINTENANCE-SDRS	28,331	83,885	98,484
512011 - INSTR/CNTRL-ENVRNL	21,885	26,124	24,917
512015 - SDRS-COMMON H2O SYS	(1,293)	(1,450)	(1,574)
512017 - MTCE-SLUDGE STAB SYS	35,251	41,726	45,603
512051 - ECR INSTR/CNTRL-ENVRNL	(1,168)	(41)	
512055 - ECR MAINTENANCE-SDRS	52,749	3,727	
512100 - MTCE-BOILER PLANT	274,402	331,396	284,980
512101 - MAINTENANCE OF SCR/NOX REDUCTION EQUIP	6,213	11,703	8,204
512102 - SORBENT INJECTION MAINTENANCE	210	1,336	1,565
512151 - ECR MAINTENANCE OF SCR/NOX REDUCTION EQUIP	(525)	4,823	9,502
512152 - ECR SORBENT INJECTION MAINTENANCE	2,568	3,195	2,558
513100 - MTCE-ELECTRIC PLANT	106,279	100,847	107,255
513900 - MTCE-ELECTRIC PLANT - BOILER	(182)	(542)	(284)
514100 - MTCE-MISC/STM PLANT	10,048	9,889	10,193
535100 - OPER SUPER/ENG-HYDRO	783	667	573
539100 - MISC HYD PWR GEN EXP	271	669	577
541100 - MTCE-SUPER/ENG - HYDRO	7,518	8,829	8,704
542100 - MAINT OF STRUCTURES - HYDRO	1,595	2,770	1,828
543100 - MTCE-RES/DAMS/WATERW			106
544100 - MTCE-ELECTRIC PLANT	1,323	2,049	4,908
545100 - MTCE-MISC HYDAULIC PLANT	190	438	149
546100 - OPER SUPER/ENG - TURBINES	11,682	15,482	16,444
549100 - MISC OTH PWR GEN EXP	2,352	2,912	3,667
551100 - MTCE-SUPER/ENG - TURBINES	2,677	2,839	2,841
552100 - MTCE-STRUCTURES - OTH PWR	7,350	9,967	10,359
553100 - DO NOT USE -- MTCE-GEN/ELECT EQ	25,914	25,776	39,538
554100 - MTCE-MISC OTH PWR GEN	5,067	5,614	4,739
556100 - SYS CTRL / DISPATCHING	13	10	
557999 - KU PLANT ALLOCATION CLEARING ACCOUNT	-	-	-
560100 - OP SUPER/ENG-SSTOPER		-	
560900 - OP SUPER/ENG-SSTOPER - INDIRECT	449	351	409
562100 - DO NOT USE -- STA EXP-SUBST OPER	23,473	27,140	34,075
566100 - MISC TRANS EXP-SSTMT	18,613	21,514	18,753
566900 - MISC TRANS EXP-SSTMT - INDIRECT	538	2,308	1,432
570100 - DO NOT USE -- MTCE-ST EQ-SSTMTCE	27,196	37,156	35,822

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Incentive Compensation Charged to A&G, O&M and Expense by Account for 2012, 2013 , and 2014

	2012	2013	2014
570900 - MTCE-ST EQ-SSTMTCE - INDIRECT		7	
571100 - MTCE OF OVERHEAD LINES	4,978	6,628	6,457
573100 - MTCE-MISC TR PLT-SSTMT	5,430	2,293	179
580100 - OP SUPER/ENG-SSTOPER	21,768	9,721	14,238
580900 - OP SUPER/ENG-SSTOPER - INDIRECT			2
582100 - STATION EXP-SSTOPER	53,862	69,562	71,718
583001 - OPR-O/H LINES	109,772	113,284	132,167
583005 - CUST COMPL RESP-O/H		26,069	
583008 - INST/REMV TRANSF/REG	133	1,326	514
583009 - INSPC O/H LINE FACIL	2,189		9
583100 - O/H LINE EXP-SSTOPER	10,279	14,735	8,947
584001 - OPR-UNDERGRND LINES	5,502	600	
584008 - INST/RMV/REPL TRANSF		21	
586100 - METER EXP	265,540	335,279	300,564
587100 - CUST INSTALLATION EXP	130	9	
588100 - MISC DIST EXP-SUBSTATION OPERATIONS	155,574	139,445	100,361
590100 - MTCE/SUPER/ENG-SSTMT	3,657	844	5,165
592100 - MTCE-ST EQ-SSTMTCE	26,596	31,197	32,312
593001 - MTCE-POLE/FIXT-DISTR	14,529	7,695	3,541
593002 - MTCE-COND/DEVICE-DIS	356,516	432,176	425,171
593003 - MTCE-SERVICES	1,648	1,254	3,778
593004 - TREE TRIMMING	37,782	35,190	33,903
593005 - MINOR EXEMPT EXPENSE		54	31
593904 - TREE TRIMMING - INDIRECT		336	
594001 - MTCE-ELEC MANHOL ETC	9,398	7,973	9,216
594002 - MTCE-U/G COND ETC	2,807	7,312	8,860
595100 - MTCE-TRANSF/REG	407	719	296
598100 - MTCE OF MISC DISTRIBUTION PLANT	1,613	1,430	2,837
Oth IS			
426501 - OTHER DEDUCTIONS	14	284	2,706
426591 - OTHER DEDUCTIONS - INDIRECT	8		
Grand Total Team Incentive Award - KU	**8,878,845**	**11,049,547**	**11,291,168**

KENTUCKY UTILITIES COMPANY

CASE NO. 2014-00371

Response to Second Set of Data Requests of
Kentucky Industrial Utility Customers, Inc.
Dated February 6, 2015

Question No. 2-17

Responding Witness: Russel A. Hudson

Q.2-17. Refer to the Company's response to AG 1-19 wherein it shows a reduction of 11 positions for "Green River transfer to metering" (due to plant retirement) and its response to AG 1-24 wherein it shows an increase of 11 positions for "meter readers" (due to regulatory compliance). Please provide a detailed explanation why the Company requires an additional 11 meter readers for regulatory compliance.

A.2-17. The 11 positions transferring from the Green River steam plant to the Metering group are a result of the retirement of the Green River Units 3 and 4. These employees will displace contractors currently in the metering positions. The increase was categorized as regulatory compliance to indicate the responsibilities these employees will now have are due to the Company's obligation to read customer meters.

KENTUCKY UTILITIES COMPANY

CASE NO. 2014-00371

Response to Second Set of Data Requests of
Kentucky Industrial Utility Customers, Inc.
Dated February 6, 2015

Question No. 2-18

Responding Witness: Russel A. Hudson

Q.2-18. Refer to the Company's response to KIUC 1-10 pages 2-6, which shows the additional positions that KU, LG&E, and LKE are projected to add by the end of the test year. for each position listed and in total for all 293 positions, provide the payroll expense (straight time, overtime, incentive) and all related expenses (payroll taxes, benefits, etc.) included in the base year and the test year in each Company's revenue requirement and on an annualized basis. Provide all assumptions, data, and calculations, including allocations of LKE costs to KU and LG&E and any costs charged from or to the two utilities, as well as the allocation between expense and capital.

A.2-18. See the response to Question No. 2-20 for the electronic spreadsheet providing all assumptions, data and calculations as requested. The tab labeled KIUC2 Q18 in the spreadsheet includes the payroll and related expenses by position as shown in KIUC 1-10.

KENTUCKY UTILITIES COMPANY

CASE NO. 2014-00371

Response to Second Set of Data Requests of
Kentucky Industrial Utility Customers, Inc.
Dated February 6, 2015

Question No. 2-19

Responding Witness: Kent W. Blake / Russel A. Hudson

Q.2-19. Refer to the Company's response to KIUC 1-7, which provided historic and projected expenses for the generating plants that will be retired by the end of the test year.

a. On the tab labeled Q.8 KU Labor, there is an amount of $ 1.927 million May 2016 for Green River Common. Please provide a description of this amount and the detailed calculation. Indicate if this includes any abnormal and nonrecurring expenses.

b. On the tab labeled KU Summary by FERC by Month, there is an amount of $1.000 million in March 2015 and an amount of $0.300 million in February 2016 for Green River 4. Please provide a description of each of these amounts and the detailed calculations. Indicate if these amounts include any abnormal and nonrecurring expenses, and if so, provide the amounts the Company believes are abnormal and nonrecurring.

c. On the tab labeled KU Summary by FERC by Month, there is an amount of $0.3000 million in October 2015 for Green River 3. Please provide a description of this amount and the detailed calculation. Indicate if this includes any abnormal and nonrecurring expenses, and if so, provide the amount the Company believes is abnormal and nonrecurring.

d. On the tab labeled KU Summary by FERC by Month, there is an amount of $1.869 million in May 2016 for Green River Common. Please provide a description of this amount and the detailed calculation. Indicate if this includes any abnormal and nonrecurring expenses, and if so, provide the amount the Company believes is abnormal and nonrecurring.

e. On the tab labeled KU Summary by FERC by Month, there is an amount of $0.200 million each month May 2016 through December 2016 for Green River Common. Please provide a description of each of these amounts and the detailed calculations. Indicate if these amounts include any abnormal and nonrecurring expenses, and if so, provide the amounts the Company believes are abnormal and nonrecurring.

A.2-19.

a. Of the $1.927 million May 2016 for Green River Common, $1.7 million is severance forecasted to be paid to 15 employees upon retirement of Green River Units 3 and 4 and another $0.159 million in payroll tax and overhead costs related to the severance. There are no abnormal or non-recurring expenses included. The remaining $0.068 million is labor expense for the five employees remaining at the plant upon its retirement. See detailed labor assumptions below:

1	Number of employees	5
2	Work days - May	22
3	Work hours - May	176
4	Average rate per employee	$64.94
5	Total base labor	$57,151.00
6	Off duty	15,539.00
7	Total chargeable labor (lines 5 - 6)	$41,612.00
8	Overhead rates	0.93328
9	Total overheads (line7 * line 8)	$38,835.65
10	Total labor (lines 7 + 9)	$80,447.65
	Allocated to balance sheet	$11,651.00
	Allocated to Income statement	$68,796.65

b. The $1.000 million in March 2015 and $0.300 million in February 2016 for Green River 4 are related to overhaul maintenance expenses during planned outages. These amounts are normal operating expenses based on planned maintenance schedules. There are no abnormal or non-recurring expenses included. Details of the outages are:

	GR4 ($000)	
	2015	**2016**
Pulverizer repairs	100	
Fan Inspection & repairs	100	
Boiler Repairs	200	
Misc Valve Replacement	50	
Precip Wash, inspection & repairs	80	
Insulation R&R	50	
Scaffolding	50	
Duct Repairs	20	
Boiler Feed Pump Inspection &	50	

Repairs		
Misc. Repairs	50	200
Cooler open/close & cleaning	200	
Precip / Air Heater clean, inspect & repair	50	100
Totals	**1,000**	**300**

c. The amount of $0.3000 million in October 2015 for Green River 3 is related to overhaul maintenance expenses during a planned outage. This amount is a normal operating expense based on planned maintenance schedule. There are no abnormal or non-recurring expenses included. Details of the outages are:

	GR3 ($000)
	2015
Precipitator wash	60
Air heater wash	20
Boiler Inspection & Repairs	100
Misc. Valve Replacement	20
Misc. Repairs	100
Total	**300**

d. See response to part a. The $1.869 million in May 2016 is the portion of the severance and labor charged to FERC account 500.

e. The $0.200 million each month May 2016 through December 2016 is for material inventory write-offs of obsolete equipment related to the retirement of Green River units 3 and 4. There are no abnormal or non-recurring expenses included.

KENTUCKY UTILITIES COMPANY

CASE NO. 2014-00371

Response to Second Set of Data Requests of
Kentucky Industrial Utility Customers, Inc.
Dated February 6, 2015

Question No. 2-20

Responding Witness: Russel A. Hudson

Q.2-20. Refer to the attachment provided by the Company' in response to KIUC 1-10 and the amounts shown on the attachment. Provide the calculations of each of these amounts in an electronic spreadsheet in sufficient detail to replicate the amounts. Provide all assumptions, the basis for all assumptions, the costs per employee, the costs for contractors, and the loadings for overtime, incentive compensation, payroll taxes, and benefits, as well as all other costs that were included in these amounts.

A.2-20. See the attachment being provided in Excel format for all details and assumptions used to develop the response to KIUC 1-10. The attachment contains personal confidential information and is being provided under seal pursuant to a Petition for Confidential Protection.

Upon further review, it was discovered there were two revisions to response 10c. for Generation and 10g. for Safety and Technical Training. 10c. for Generation previously reported 23 employees for LG&E and 47 employees for KU; revised to 31 employees LG&E and 39 employees KU. 10g. for Safety and Technical Training previously reported costs of $89,103 and $120,971 for LG&E and KU, respectively; revised to ($6,746) and ($9,159) for LG&E and KU, respectively.

Attachment
Confidential

The entire attachment is Confidential and provided separately under seal.

KENTUCKY UTILITIES COMPANY

CASE NO. 2014-00371

Response to Second Set of Data Requests of
Kentucky Industrial Utility Customers, Inc.
Dated February 6, 2015

Question No. 2-21

Responding Witness: Daniel K. Arbough

Q.2-21. Referring to the Company's response to PSC-1 Question No. 7:

a. Please provide the yearly amounts of long-term purchased power obligations considered by rating agencies in calculating KU's Fixed Charge Coverage Ratios.

b. Please provide the rating agency financial ratios for KU over that last ten years. Please provide all work papers and supporting calculations with spreadsheets and cell formulas intact. The response should include the ratios used by Standard and Poor's and Moody's used to evaluate KU's bond and credit ratings and show each component part of the ratio is calculated.

A.2-21.

a. See the attachment for a listing of power KU actually purchased under long-term purchase agreements that the rating agencies evaluate as possible debt equivalents. Standard and Poor's and Moody's have their own methodologies for determining the adjustments to debt and interest expense resulting from purchased power that impact the Fixed Charge Coverage ratios.

b. The attached rating agency reports from Moody's and Standard Poor's are the reports readily available that include financial ratios. The Company does not have access to the spreadsheets used by the rating agencies in calculating these ratios.

KU Purchased Power Obligations

Demand Charges	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013
Dynegy Power Marketing, Inc.					1,386,000	1,543,812				
Electric Energy, Inc.	13,608,883	13,983,247	2,012,700							
Ohio Valley Electric Corporation	2,996,990	2,136,121	1,586,227	1,324,708	6,583,170	7,391,282	7,886,336	8,194,423	8,600,747	8,992,720
Owensboro Municipal Utilities	16,096,961	14,398,331	14,262,076	14,377,752	15,251,995	16,975,696	8,695,690	-	-	-
Total Demand Charges	32,702,834	30,517,699	17,861,003	15,702,460	23,221,165	25,910,790	16,582,026	8,194,423	8,600,747	8,992,720

Energy Charges	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013
Dynegy Power Marketing, Inc.					4,916,424	2,013,748				
Electric Energy, Inc.	17,279,458	18,116,845	(164,101)							
Ohio Valley Electric Corporation	6,494,507	8,620,657	8,829,087	7,240,670	8,407,658	8,296,452	9,236,572	9,760,521	8,921,457	8,021,563
Owensboro Municipal Utilities	25,885,443	24,230,779	25,567,281	30,783,045	41,085,207	51,203,094	20,116,271			
Total Energy Charges	49,659,408	50,968,281	34,232,267	38,023,715	54,409,289	61,513,294	29,352,843	9,760,521	8,921,457	8,021,563

Total Demand and Energy Charges	**82,362,242**	**81,485,980**	**52,093,270**	**53,726,175**	**77,630,454**	**87,424,084**	**45,934,869**	**17,954,944**	**17,522,204**	**17,014,283**

MOODY'S
INVESTORS SERVICE

Credit Opinion: Kentucky Utilities Co.

Global Credit Research - 08 Dec 2014

Lexington, Kentucky, United States

Ratings

Category	Moody's Rating
Outlook	Stable
Issuer Rating	A3
First Mortgage Bonds	A1
Senior Secured Shelf	(P)A1
Sr Unsec Bank Credit Facility	A3
Commercial Paper	P-2
Ult Parent: PPL Corporation	
Outlook	Positive
Issuer Rating	Baa3
Pref. Shelf	(P)Ba2
Parent: LG&E and KU Energy LLC	
Outlook	Positive
Issuer Rating	Baa2
Senior Unsecured	Baa2

Contacts

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Opinion

Rating Drivers

- Supportive regulatory environment

- Large capital expenditure program

- High coal concentration

- Strong and stable financial metrics

Corporate Profile

Kentucky Utilities (KU: A3 stable) is a regulated public utility engaged in the generation, transmission and distribution of electricity. KU provides electric service to approximately 514,000 customers in Kentucky and 29,000 customers in Virginia. Its service territory covers approximately 4,800 square miles.

KU is a wholly-owned subsidiary of LG&E and KU Energy LLC (LKE: Baa1 stable). KU and its affiliate, Louisville Gas and Electric Company (LG&E: A3 stable), are the two main operating entities of LKE. LKE, in turn, is wholly owned by PPL Corporation (PPL: Baa3 positive), a diversified energy holding company headquartered in Allentown, PA.

SUMMARY RATING RATIONALE

KU's A3 issuer rating reflects its sound financial performance and the credit supportive regulatory environment in which it operates, offset in part by a large capital expenditure program and, to a lesser extent, a lack of fuel and geographic diversity.

DETAILED RATING CONSIDERATIONS

SUPPORTIVE REGULATION PROVIDES FOR TIMELY COST RECOVERY

We consider the Kentucky Public Service Commission (KPSC) to be supportive of long term credit quality and note that it has approved various tracker mechanisms that provide for timely cost recovery outside of a rate case. KU's tracker mechanisms include a Fuel Adjustment Clause (FAC), an Environmental Cost Recovery Surcharge (ECR) and a Demand-Side Management Cost Recovery Mechanism (DSM). KU does not have a decoupling mechanism in place, which subjects KU's net revenue to weather volatilities. The lack of a decoupling mechanism is less of an issue for non-weather related demand fluctuations because KU has the DSM and expects to have modest load growth in 2015.

In December 2012, the KPSC approved KU's settlement regarding the rate case filed in June 2012 which requested a base rate increase of $82 million for electricity (6.5%), to take effect in January, 2013. The settlement granted KU an increase in electric base rates of $51 million with an authorized ROE of 10.25%. The rate case progressed without being unusually controversial or contentious; we consider the decision a constructive result. Due to the high level of planned capital expenditures, LG&E and KU filed a rate case in November of 2014, requesting increases in annual base electricity rates of approximately $30 million at LG&E and approximately $153 million at KU along with an increase in annual base gas rates of approximately $14 million at LG&E. The proposed base rate increases would result in electricity rate increases of 2.7% at LG&E and 9.6% at KU and a gas rate increase of 4.2% at LG&E. All would become effective in July 2015.

LARGE PLANNED CAPITAL EXPENDITURES

Capital expenditures for KU are expected to remain at elevated levels from 2014-2018. Total capital expenditures are expected to be $2.7 billion, with $1 billion related to environmental. The total estimated amount represents about 44% of its net book value of property, plant and equipment, which stoods at about $6.1 billion at the end of the third quarter 2014.

The disallowance risk associated with large capital expenditures is meaningfully moderated by Kentucky's supportive regulatory environment as detailed above. KPSC is also authorized to grant return on construction work in progress (CWIP) in rate case proceedings. Moreover, the ECR virtually eliminates regulatory lag for investments associated with complying with the Clean Air Act and coal combustion waste and byproduct environmental requirements. The terms of the ECR allows KU to receive the return of and a return on the investment starting two months after making the investment. This is highly favorable compared to the traditional process where regulatory lag could last a few years due to the length of the construction period plus the rate case proceeding.

HIGH COAL CONCENTRATION

KU's current fuel mix is heavily biased towards coal. Of its 4.7 GW of generating capacity, 3.2 GW (67%) is coal-fired which provides almost all (98%) of the electricity generation. The remaining 33% of the generating capacity is comprised mainly of gas- or oil- fired facilities that are utilized as peakers.

The fuel concentration, though a credit negative, is acceptable for its rating levels because Kentucky is very supportive of the coal industry. Kentucky is one of the leading coal producing states and the coal industry is very important to the local economy. This support is evidenced by the passage of the ECR, which provides the company with highly favorable terms for its investments in coal-related environmental expenditures.

KU's fuel concentration mix may also improve in the future as KU, along with LG&E, is building a 640-MW gas-fired combined cycle plant at Cane Run. The Cane Run gas plant is under construction and due to be completed by the end of 2015. Cane Run will replace some of the less economic coal plants totaling 234 MW at Tyrone and Green River, as well as the 563 MW retirement of Cane Run coal plant in 2015. KU and LG&E had also planned to build a 700-MW gas-fired combined-cycle plant at KU's Green River generating site but the companies withdrew that proposal in August 2014 as a result of municipal contract terminations at KU.

HEALTHY FINANCIAL PROFILE

KU's financial metrics have been strong for its rating. As of September 30, 2014, the ratio of consolidated cash flow before changes in working capital (CFO pre W/C) to debt was 26% for the last twelve months and for the average of the past three years. Debt to capitalization was 36% for the last twelve months and for the average over the past three years. KU's financial metrics may decline somewhat over the next few years due to the expiration of bonus depreciation after 2013 and the large capital expenditure program. However, we expect KU's financial metrics to remain supportive of its rating levels based on the company's targeted capital structure of 52% equity, which is calculated net of goodwill and fully loaded with rating agency adjustments. KU's goodwill amounted to $607 million at the end of September 2014 and in comparison total equity, including the goodwill, was $3,170 million.

Liquidity Profile

KU has adequate liquidity. As of September 30, 2014, after accounting for all commercial paper backup and letter of credits issued, KU had $270 million available under its $400 million revolving facility. For the past twelve months ending September 2014, KU had a negative free cash flow of $352 million which is likely to be more sizeable in the coming years given its large capital expenditure program. KU's next long-term debt maturity is a $250 million first mortgage bond issuance due November 2015.

LKE manages the liquidity of its Kentucky utility operations on a consolidated basis. KU has a $400 million stand-alone revolving credit facility and LG&E, it sister affiliate, has a $500 million stand-alone credit facility. Both facilities expire in July 2019. LKE, KU's parent company, also has a $75 million syndicated credit facility that expires in October 2018. Each facility contains a financial covenant requiring the companies' debt to total capitalization not to exceed 70%. All entities were in compliance as of September 30, 2014.

Rating Outlook

KU's stable outlook reflects its supportive regulatory environment and solid financial performance.

What Could Change the Rating - Up

The potential for upgrade is low due to the large upcoming capital expenditure programs. However, upward pressure could result should the company receive more favorable regulatory recovery mechanisms for non-environmental related capital expenditures and maintain its CFO Pre WC/debt ratios at 26% or above.

What Could Change the Rating - Down

KU's ratings could be downgraded should the company experience an unfavorable rate case outcome or if unanticipated changes were made to the regulatory compact that currently provides for timely recovery of costs and this were to lead to the company's ratios of CFO pre-WC to debt and retained cash flow to debt dropping below 20% and 15%, respectively, for an extended period of time.

Rating Factors

Kentucky Utilities Co.

Regulated Electric and Gas Utilities Industry Grid [1][2]	Current LTM 9/30/2014		[3]Moody's 12-18 Month Forward ViewAs of December 2014	
Factor 1 : Regulatory Framework (25%)	Measure	Score	Measure	Score
a) Legislative and Judicial Underpinnings of the Regulatory Framework	A	A	A	A
b) Consistency and Predictability of Regulation	A	A	A	A
Factor 2 : Ability to Recover Costs and Earn Returns (25%)				
a) Timeliness of Recovery of Operating and Capital Costs	Baa	Baa	Baa	Baa
b) Sufficiency of Rates and Returns	A	A	A	A
Factor 3 : Diversification (10%)				
a) Market Position	Baa	Baa	Baa	Baa
b) Generation and Fuel Diversity	Baa	Baa	Baa	Baa
Factor 4 : Financial Strength (40%)				

a) CFO pre-WC + Interest / Interest (3 Year Avg)	8.2x	Aaa	6x-8x	Aa
b) CFO pre-WC / Debt (3 Year Avg)	25.7%	A	22%-26%	A
c) CFO pre-WC - Dividends / Debt (3 Year Avg)	19.8%	A	16%-19%	A
d) Debt / Capitalization (3 Year Avg)	36.3%	A	35%-40%	A
Rating:				
Grid-Indicated Rating Before Notching Adjustment		A2		A2
HoldCo Structural Subordination Notching				
a) Indicated Rating from Grid		A2		A2
b) Actual Rating Assigned		A3		A3

[1] All ratios are based on 'Adjusted' financial data and incorporate Moody's Global Standard Adjustments for Non-Financial Corporations. [2] As of latest 9/30/2014; Source: Moody's Financial Metrics [3] This represents Moody's forward view; not the view of the issuer; and unless noted in the text, does not incorporate significant acquisitions and divestitures.

This publication does not announce a credit rating action. For any credit ratings referenced in this publication, please see the ratings tab on the issuer/entity page on http://www.moodys.com for the most updated credit rating action information and rating history.

MOODY'S
INVESTORS SERVICE

MOODY'S
INVESTORS SERVICE

Credit Opinion: Kentucky Utilities Co.

Global Credit Research - 08 Dec 2013

Lexington, Kentucky, United States

Ratings

Category	Moody's Rating
Outlook	Rating(s) Under Review
Issuer Rating	*Baa1
First Mortgage Bonds	*A2
Senior Secured Shelf	*(P)A2
Sr Unsec Bank Credit Facility	*Baa1
Commercial Paper	P-2
Ult Parent: PPL Corporation	
Outlook	Rating(s) Under Review
Issuer Rating	*Baa3
Pref. Shelf	*(P)Ba2
Parent: LG&E and KU Energy LLC	
Outlook	Rating(s) Under Review
Issuer Rating	*Baa2
Senior Unsecured	*Baa2

* Placed under review for possible upgrade on November 8, 2013

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Opinion

Rating Drivers

- Supportive regulatory environment

- Large capital expenditure program

- High coal concentration

- Strong and stable financial metrics

Corporate Profile

Kentucky Utilities (KU: Baa1 Issuer Rating) is a regulated public utility engaged in the generation, transmission and distribution of electricity. KU provides electric service to approximately 510,000 customers in Kentucky and 29,000 customers in Virginia. Its service territory covers approximately 4,800 square miles.

KU is a wholly-owned subsidiary of LG&E and KU Energy LLC (LKE: Baa2 Issuer Rating). KU and its affiliate, Louisville Gas and Electric Company (LG&E: Baa1 Issuer Rating), are the two main operating entities of LKE. LKE in turn is wholly owned by PPL Corporation (PPL: Baa3 Issuer Rating), a diversified energy holding company headquartered in Allentown, PA.

SUMMARY RATING RATIONALE

KU's Baa1 Issuer Rating reflects its sound financial performance and the credit supportive regulatory environment in which it operates, offset in part by a large capital expenditure program and, to a lesser extent, a lack of fuel and geographic diversity.

DETAILED RATING CONSIDERATIONS

SUPPORTIVE REGULATION PROVIDES FOR TIMELY COST RECOVERY

We consider the Kentucky Public Service Commission (KPSC) to be supportive of long term credit quality and note that it has approved various tracker mechanisms that provide for timely cost recovery outside of a rate case. KU's tracker mechanisms include a Fuel Adjustment Clause (FAC), an Environmental Cost Recovery Surcharge (ECR) and a Demand-Side Management Cost Recovery Mechanism (DSM). KU does not have a decoupling mechanism in place, which subjects KU's net revenue to weather volatilities. The lack of a decoupling mechanism is less of an issue for non-weather related demand fluctuations because KU has the DSM and expects to have modest load growth in 2014.

In December 2012, the KPSC approved KU's settlement regarding the rate case filed in June 2012 which requested a base rate increase of $82 million for electricity (6.5%), to take effect in January, 2013. The settlement granted KU an increase in electric base rates of $51 million with an authorized ROE of 10.25%. The rate case progressed without being unusually controversial or contentious; we consider the decision a constructive result. Due to the high level of planned capital expenditures, KU is likely to file for another rate case in 2014.

LARGE PLANNED CAPITAL EXPENDITURES

Capital expenditures for KU are expected to remain at elevated levels from 2013-2017. Total capital expenditures are expected to be $3.1 billion, with $1.2 billion related to environmental. The total estimated amount represents about 56% of its net book value of property, plant and equipment, which stands at about $5.5 billion at the end of the third quarter 2013.

The disallowance risk associated with large capital expenditures is meaningfully moderated by Kentucky's supportive regulatory environment as detailed above. KPSC is also authorized to grant return on construction work in progress (CWIP) in rate case proceedings. Moreover, the ECR virtually eliminates regulatory lag for investments associated with complying with the Clean Air Act and coal combustion waste and byproduct environmental requirements. The terms of the ECR allows KU to receive the return of and a return on the investment starting two months after making the investment. This is highly favorable compared to the traditional process where regulatory lag could last a few years due to the length of the construction period plus the rate case proceeding.

HIGH COAL CONCENTRATION

KU's current fuel mix is heavily biased towards coal. Of its 4.8 GW of generating capacity, 3.4 GW (69%) is coal-fired and it provides almost all (95%) of generation. The remaining 31% of the generating capacity is comprised mainly of gas- or oil- fired facilities that are utilized as peakers.

The fuel concentration, though a credit negative, is acceptable for its rating levels because Kentucky is very supportive of the coal industry. Kentucky is one of the leading coal producing states and the coal industry is very important to the local economy. The support is evidenced by the passage of the ECR, which provides the company with highly favorable terms for its investments in coal-related environmental expenditures.

KU's fuel mix may also improve in the future as KU, along with LG&E, is building a 640-MW gas-fired combined cycle plant at Cane Run and plans to build a 700-MW gas-fired combined-cycle plant at KU's Green River generating site. The Cane Run gas plant is under construction and due to be completed by the end of 2015. Cane Run will replace some of the less economic coal plants totaling 234 MW at Tyrone and Green River that are being closed. The construction of the Green River gas plant has been announced but not yet approved. If approved, it is expected to be in service by end of 2018 to accommodate expected load growth.

The operating status of E.W. Brown unit 1 & 2, which accounts for 172 MW of coal generation capacity, was in question due to environmental compliance concerns. However, the company now believes that it can continue to operate the plant for a few more years without a major environmental retrofit.

HEALTHY FINANCIAL PROFILE

KU's financial metrics have been strong for its rating. As of September 30, 2013, the ratio of consolidated cash flow before changes in working capital (CFO pre W/C) to debt was 26% for the last twelve months and averaged 24% for the past three years. Debt to capitalization was 36% for the last twelve months and averaged 37% for the past three years. KU's financial metrics may decline somewhat over the next few years due to the expiration of bonus depreciation after 2013 and the large capital expenditure program. However, we expect KU's financial metrics to remain supportive of its rating levels based on the company's targeted capital structure of 52% equity, which is calculated net of goodwill and fully loaded with rating agency adjustments. KU's goodwill amounted to $607 million at the end of September 2013 and in comparison the total equity, including the goodwill, was $2,963 million.

Liquidity Profile

KU has adequate liquidity. As of September 30, 2013, after accounting for all commercial paper backup and letter of credits issued, KU has $260 million available under its $400 million revolving facility. For the past twelve months ending September 2013, KU had a negative free cash flow of $267 million which is likely to be sizeable in the coming years given its large capital expenditure program. KU's next long-term debt maturity is a $250 million first mortgage bond issuance due November 2015.

LKE manages the liquidity of its Kentucky utility operations on a consolidated basis. KU has a $400 million stand-alone revolving credit facility and LG&E, it sister affiliate, has a $500 million stand-alone credit facility. Both facilities expire in November 2017. In October 2013, LKE, KU's parent company, entered into a $75 million syndicated credit facility that expires in October 2018. Each facility contains a financial covenant requiring the companies' debt to total capitalization not to exceed 70%. All entities were in compliance as of September 30, 2013.

Rating Outlook

The review for upgrade reflects our improved view of US utility regulatory relations and credit-supportiveness generally, as exemplified in Kentucky with regulatory outcomes including a strong suite of recovery mechanisms. The continued above-average performance in KU's financial metrics over the near-term driven in part by the credit supportive environment is also a consideration.

What Could Change the Rating - Up

KU could be upgraded by one notch following the review process currently underway.

What Could Change the Rating - Down

KU's ratings could be downgraded should the company experience an unfavorable rate case outcome or if unanticipated changes were made to the regulatory compact that currently provides for timely recovery of costs and this were to lead to the company's ratios of CFO pre-WC to debt and retained cash flow to debt dropping below 20% and 15%, respectively, for an extended period of time.

Rating Factors

Kentucky Utilities Co.

Regulated Electric and Gas Utilities Industry [1][2]	LTM 09/30/2013		Moody's 12-18 month Forward View* As of November 2013	
Factor 1: Regulatory Framework (25%)	Measure	Score	Measure	Score

a) Regulatory Framework		Baa		Baa
Factor 2: Ability To Recover Costs And Earn Returns (25%)				
a) Ability To Recover Costs And Earn Returns		A		A
Factor 3: Diversification (10%)				
a) Market Position (5%)		Baa		Baa
b) Generation and Fuel Diversity (5%)		B		B
Factor 4: Financial Strength, Liquidity And Key Financial Metrics (40%)				
a) Liquidity (10%)		Baa		Baa
b) CFO pre-WC + Interest/ Interest (3 Year Avg) (7.5%)	7.6x	Aa	7.5-7.8x	Aa
c) CFO pre-WC / Debt (3 Year Avg) (7.5%)	24.4%	A	22-25%	A
d) CFO pre-WC - Dividends / Debt (3 Year Avg) (7.5%)	19.3%	A	17-20%	A
e) Debt/Capitalization (3 Year Avg) (7.5%)	36.9%	A	36-38%	A
Rating:				
a) Indicated Rating from Grid		A3		A3
b) Actual Rating Assigned		Baa1		A3

* THIS REPRESENTS MOODY'S FORWARD VIEW; NOT THE VIEW OF THE ISSUER; AND UNLESS NOTED IN THE TEXT DOES NOT INCORPORATE SIGNIFICANT ACQUISITIONS OR DIVESTITURES

[1] All ratios are calculated using Moody's Standard Adjustments. [2] As of 09/30/2013(LTM); Source: Moody's Financial Metrics

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MOODY'S
INVESTORS SERVICE

Credit Opinion: Kentucky Utilities Co.

Global Credit Research - 19 Nov 2012

Lexington, Kentucky, United States

Ratings

Category	Moody's Rating
Outlook	Stable
Issuer Rating	Baa1
First Mortgage Bonds	A2
Senior Secured Shelf	(P)A2
Sr Unsec Bank Credit Facility	Baa1
Commercial Paper	P-2
Ult Parent: PPL Corporation	
Outlook	Stable
Issuer Rating	Baa3
Pref. Shelf	(P)Ba2
Parent: LG&E and KU Energy LLC	
Outlook	Stable
Issuer Rating	Baa2
Senior Unsecured	Baa2

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Opinion

Rating Drivers

Supportive regulatory environment

Large capital expenditure program

High coal concentration

Healthy and stable financial metrics

Moderate drag from family-wide business risk

Corporate Profile

Kentucky Utilities (KU; Baa1 Issuer Rating) is a regulated public utility engaged in the generation, transmission and distribution of electricity. KU provides electric service to approximately 510,000 customers in Kentucky and 29,000 customers in Virginia. Its service territory covers approximately 4,800 square miles.

KU is a wholly-owned subsidiary of LG&E and KU Energy LLC (LKE: Baa2 Issuer Rating). KU and its affiliate, Louisville Gas and Electric Company (LG&E: Baa1 Issuer Rating), are two main operating entities of LKE. LKE in turn is a wholly owned by PPL Corporation (PPL: Baa3 Issuer Rating), a diversified energy holding company headquartered in Allentown, PA.

SUMMARY RATING RATIONALE

KU's Baa1 Issuer Rating reflects its sound financial performance and the credit supportive regulatory environment in which it operates offset in part by a large capital expenditure program and, to a lesser extent, a lack of fuel and geographic diversity.

DETAILED RATING CONSIDERATIONS

SUPPORTIVE REGULATION PROVIDES FOR TIMELY COST RECOVERY

We consider the regulatory authorities in Kentucky as being supportive to long term credit quality and note that the Kentucky Public Service Commission (KPSC) has approved various tracking mechanisms that provide for timely cost recovery outside of a rate case. Approved tracking mechanisms in KU's electric rates include a Fuel Adjustment Clause (FAC), an Environmental Cost Recovery Surcharge (ECR) and a Demand-Side Management Cost Recovery Mechanism (DSM).

The FAC is adjusted monthly and allows the company to adjust rates for the difference between the fuel cost component of base rates and the actual fuel costs. Additional charges (or credits) to customers occur if actual fuel costs exceed (or are below) the embedded cost component. The KPSC requires public hearings at six-month intervals to examine past fuel adjustments.

The ECR provides recovery of costs associated with complying with the Clean Air Act as Amended and environmental requirements which applies to coal combustion wastes and byproducts. This is an important factor given that KU continues to invest significantly in emission control devices. Proceedings are conducted every six-months to evaluate the operation of the ECR.

Rates also include a DSM provision which includes a rate mechanism that provides for concurrent recovery of DSM costs, including a return on capital, and provides an incentive for implementing DSM programs.

KU has a pending rate case which was filed in June 2012. The request includes a base rate increase of $82.4 million (6.5%) to take effect in January 2013. So far, this rate case has progressed without being unusually controversial or contentious. We considered the regulatory treatment of the last rate case to be constructive. KU's last rate case was concluded in July 2010 and resulted in $98 million (8.3%) increase in base rates for KU.

LARGE PLANNED CAPITAL EXPENDITURES

Capital expenditures for KU are expected to remain at elevated levels from 2012-2016. Total capital expenditures are expected to be $3 billion, with $1.4 billion related to environmental. The total estimated amount represents about 60% of its net book value of property, plant and equipment, which stands at about $4.9 billion at the end of third quarter 2012.

While this large capital expenditure amount raises the exposure to possible disallowance, this risk is meaningfully moderated by Kentucky's supportive regulatory environment as detailed above. More specifically, KPSC approved $850 million of environmental spending in December of 2011 through the ECR surcharge mechanism. This approval sets a return on equity of 10.1% on the $850 million but allows a return of 10.63% on previously approved projects. The ECR mechanism provides return on construction work during progress and reduces the potential for disallowance.

HIGH COAL CONCENTRATION

KU's current fuel mix is heavily biased towards coal. Of its 4.8 GW of generating capacity, 3.4 GW (69%) is coal-fired and it provides almost all (98%) of the energy production. The remaining 31% of the generating capacity is comprised mainly of gas- or oil- fired facilities that are utilized as peakers. KU's fuel mix may modestly improve in the future as KU, along with LG&E, plans to build a 640-MW gas-fired combined cycle plant at Cane Run by end of 2015 to replace some of its less economic coal plants totaling 234 MW at Tyrone and Green River. KU is also evaluating the trade-offs between installing additional emission control for two units totaling 272 MW at the E.W. Brown coal facility versus purchasing power from a third-party or building new plants. Shutting down the two units at E.W. Brown could result in a further move away from coal.

We score KU a "B" for Factor 3; Sub-factor 2, Generation and Fuel Diversification to reflect the high coal concentration.

HEALTHY FINANCIAL PROFILE

KU's financial metrics have remained relatively healthy, with a ratio of consolidated cash flow before changes in working capital (CFO pre W/C) to debt averaging nearly 20%, retained cash flow to debt averaging a healthy 17% and CFO pre-W/C interest coverage averaging 5.8 times over the past three years. However, these results were temporarily bolstered by bonus depreciation. An important rating consideration will be the manner in which future capital investment is financed to include, when necessary, an anticipated issuance of PPL common equity to help finance the very large amount of planned capital investment.

MODERATE DRAG FROM FAMILY-WIDE BUSINESS RISK

KU's credit quality is moderately impacted by the riskier family-wide risk profile due to its affiliates' involvement in unregulated generation. Unregulated activity current represents about 25%-30% of PPL's consolidated net income. However, its share has been declining and will likely continue to decline as PPL continues to grow its regulated operations through acquisitions (most recently the acquisition of PPL WEM Holdings in 2011) and elevated growth in rate base ($8 to $9 billion over the next three years). Earning contribution from PPL's merchant operations is also down because of low power prices.

Liquidity Profile

KU has ample liquidity. Though KU has a $400 million stand-alone revolving credit facility, LKE manages the liquidity of its Kentucky utility operations on a consolidated basis. KU's sister affiliate, LG&E, has larger facility with a $500 million capacity. Both facilities expire in November 2017.

Additionally, LKE, KU, and LG&E all participate in an intercompany money pool agreement whereby LKE and/or the operating subsidiaries can make available any excess funds (up to $500 million) to their affiliate utility at market-based rates. LKE also has intercompany borrowing access from PPL Investment Corporation to borrow up to $300 million on an intercompany basis.

Moody's observes that at September 30, 2012, both KU and LG&E had full access to each of their respective revolvers. Each facility contains a financial covenant requiring the utility's debt to total capitalization not to exceed 70%, as calculated in accordance with the credit facility. Also, in April 2011, KU entered into an additional $198 million letter of credit facility expiring in April 2014, which KU uses to support outstanding tax-exempt bonds.

As capital investment increases, we anticipate LKE and its subsidiaries becoming more active short-term borrowers with an eye towards permanently funding the short-term debt with periodic issuances of long-term debt and equity contributions from PPL.

Rating Outlook

The stable outlook considers the continued above-average performance in KU's financial metrics over the near-term driven in part by credit supportive regulatory outcomes including a strong suite of recovery mechanisms. The stable outlook further considers our belief that the sizeable capital investment program will be financed in a credit benign manner to include the issuance of equity when needed.

What Could Change the Rating - Up

In light of a very large multi-year capital spending program, prospects for an upgrade may be challenging in the near-term. However, should KU finance its material capital expenditures in a conservative fashion and maintain a favorable regulatory construct, KU's rating could be upgraded, particularly if its ratios of CFO pre-WC to debt and retained cash flow to debt exceed 22% and 17%, respectively, on a sustained basis.

What Could Change the Rating - Down

KU's ratings could be downgraded should the company experience an unfavorable rate case outcome or if unanticipated changes were made to the regulatory compact that currently provides for timely recovery of costs leading to the company's ratios of CFO pre-WC to debt and retained cash flow to debt dropping below 16% and 11%, respectively.

Other Considerations

Moody's evaluates KU's consolidated financial performance relative to the Regulated Electric and Gas Utilities rating methodology published in August 2009 and as depicted in the grid below, KU's indicated rating under this methodology on both a historical and projected basis is Baa1 consistent with current Issuer Rating.

Rating Factors

Kentucky Utilities Co.

Regulated Electric and Gas Utilities Industry [1][2]	Current LTM 6/30/2012		Moody's 12-18 month Forward View* As of November 2012	
Factor 1: Regulatory Framework (25%)	Measure	Score	Measure	Score
a) Regulatory Framework		Baa		Baa
Factor 2: Ability To Recover Costs And Earn Returns (25%)				
a) Ability To Recover Costs And Earn Returns		A		A
Factor 3: Diversification (10%)				
a) Market Position (5%)		Baa		Baa
b) Generation and Fuel Diversity (5%)		B		B
Factor 4: Financial Strength, Liquidity And Key Financial Metrics (40%)				
a) Liquidity (10%)		Baa		Baa
b) CFO pre-WC + Interest/ Interest (3 Year Avg) (7.5%)	6.3x	Aa	6.2-7x	Aa
c) CFO pre-WC / Debt (3 Year Avg) (7.5%)	22.1%	A	20-24%	A
d) CFO pre-WC - Dividends / Debt (3 Year Avg) (7.5%)	18.3%	A	14-18%	A
e) Debt/Capitalization (3 Year Avg) (7.5%)	39.8%	A	37-41%	A
Rating:				
a) Indicated Rating from Grid		A3		Baa1
b) Actual Rating Assigned		Baa1		Baa1

* THIS REPRESENTS MOODY'S FORWARD VIEW; NOT THE VIEW OF THE ISSUER; AND UNLESS NOTED IN THE TEXT DOES NOT INCORPORATE SIGNIFICANT ACQUISITIONS OR DIVESTITURES

[1] All ratios are calculated using Moody's Standard Adjustments. [2] As of LTM 6/30/2012(L); Source: Moody's Financial Metrics

MOODY'S
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MJKK's current opinions of the relative future credit risk of entities, credit commitments, or debt or debt-like securities. In such a case, "MIS" in the foregoing statements shall be deemed to be replaced with "MJKK". MJKK is a wholly-owned credit rating agency subsidiary of Moody's Group Japan G.K., which is wholly owned by Moody's Overseas Holdings Inc., a wholly-owned subsidiary of MCO.

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MOODY'S
INVESTORS SERVICE

Credit Opinion: Kentucky Utilities Co.

Global Credit Research - 16 Nov 2011

Lexington, Kentucky, United States

Ratings

Category	Moody's Rating
Outlook	Stable
Issuer Rating	Baa1
First Mortgage Bonds	A2
Sr Unsec Bank Credit Facility	Baa1
Ult Parent: PPL Corporation	
Outlook	Stable
Issuer Rating	Baa3
Parent: LG&E and KU Energy LLC	
Outlook	Stable
Issuer Rating	Baa2
Senior Unsecured	Baa2

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Opinion

Rating Drivers

Regulatory environment provides for timely recovery of costs

Constructive outcome of most recent rate case and recently announced settlement fortifies credit supportive regulatory environment

Elevated capital expenditure spending program due to environmental initiatives

Lack of fuel diversity relating to its electric generating portfolio

Healthy and stable financial metrics

PPL's acquisition strategy has reduced family-wide business risk

Corporate Profile

Kentucky Utilities (KU; Baa1 Issuer Rating) is a regulated public utility engaged in the generation, transmission and distribution of electricity. KU provides electric service to approximately 516,000 customers in Kentucky and 30,000 customers in Virginia. Its service territory covers approximately 6,600 square miles. KU's coal-fired electric generating plants produce most of its electricity.

KU is a wholly-owned subsidiary of LG&E and KU Energy LLC (LKE: Baa2 Issuer Rating). KU and its affiliate, Louisville Gas and Electric Company (LG&E: Baa1 Issuer Rating), are separate operating entities of LKE, wholly owned by PPL Corporation (PPL: Baa3 Issuer Rating), a diversified energy holding company headquartered in Allentown, PA.

SUMMARY RATING RATIONALE

KU's Baa1 Issuer Rating reflects its sound financial performance and the credit supportive regulatory environment offset in part by a lack of fuel diversity relating to its electric generating portfolio, a modestly sized service territory, and a large capital expenditure program.

DETAILED RATING CONSIDERATIONS

SUPPORTIVE REGULATION PROVIDES FOR TIMELY COST RECOVERY

In July 2010, the Kentucky Public Service Commission (KPSC) issued an order relating to KU and LG&E's January 2010 rate case filings with new rates effective August 1, 2010. Specifically, KU was granted a $98 million electric rate increase, or 73% of its requested $135 million increase. LG&E was granted a $74 million electric rate increase, or 78% of its requested $95 million increase and a $17 million gas rate increase (74% of the $23 million requested). The KPSC order was based on an ROE range of 10.0 to 10.5%.

Moody's considers the regulatory authorities in Kentucky as being generally supportive to long term credit quality and notes that the KPSC has approved various tracking mechanisms that provide for timely cost recovery outside of a rate case. As part of a settlement agreement relating to the PPL's acquisition and approved by the KPSC, KU and LG&E agreed to a moratorium on any base rate increase until January 2013. As such, the utilities may be challenged to control their respective operating expenses during this period; however, approved tracking mechanisms in KU's electric rates include a Fuel Adjustment Clause (FAC), an Environmental Cost Recovery Surcharge (ECR) and a Demand-Side Management Cost Recovery Mechanism (DSM) should help in managing the operating margin during the interim period. The FAC is adjusted monthly and allows the company to adjust rates for the difference between the fuel cost component of base rates and the actual fuel costs. Additional charges (or credits) to customers occur if actual fuel costs exceed (or are below) the embedded cost component. The KPSC requires public hearings at six-month intervals to examine past fuel adjustments.

The ECR provides KU recovery of costs associated with complying with the Clean Air Act as Amended and any other environmental requirement which applies to coal combustion wastes and byproducts. This is an important factor given that KU and LG&E continue to invest significantly in emission control devices. Proceedings are conducted every six-months to evaluate the operation of the ECR. LG&E's rates also include a DSM provision which includes a rate mechanism that provides for concurrent recovery of DSM costs and provides an incentive for implementing DSM programs.

In Virginia, KU filed an application in April 2011 with the Virginia Commission requesting an annual increase in base rates for its Virginia customers of $9.3 million or approximately 14%, which is equivalent to an 11% return on equity. In September 2011, a settlement stipulation was reached between KU and the Virginia Commission staff. In October 2011, the Virginia Commission approved the stipulation with two modifications that were accepted by KU. The approved annual revenue increase is $7 million with new base rates effective November 1, 2011.

SETTLEMENT WITH INTERVENORS LARGELY ADDRESSES MAJOR ENVIRONMENTAL OVERHANG

In June 2011, KU and LG&E filed a new ECR to request approval to install environmental upgrades for their coal-fired plants along with the recovery of the expected $2.5 billion in costs. The applications sought approval to install environmental upgrades at certain of the plants during 2012-2016, including recovery through the ECR surcharge mechanism of approximate capital costs of $1.1 billion at KU and $1.4 billion at LG&E, plus operating expenses. On November 9, 2011, KU and LG&E entered into a settlement agreement with the interveners in their proceedings before the KPSC relating to their proposed ECR plans. The settlement provides that the parties will favorably recommend to the KPSC for approval, or not oppose, approximately $2.25 billion of the $2.5 billion in capital projects for which approval was originally requested, constituting approximately $883 million and $1.4 billion at KU and LG&E, respectively. Under the settlement, the $217 million in remaining capital costs are deferred and may be the subject of future regulatory proceedings for approval to construct the deferred projects and recover the associated costs through the ECR surcharge mechanism. The deferred projects relate to certain proposed environmental upgrades at KU's E.W. Brown plant, for which KU retains the right to operate and dispatch in accordance with applicable environmental standards. The settlement confirms an existing 10.63% authorized return on equity for projects remaining from earlier ECR plans and provides for an authorized return on equity of 10.10% for this filing.

As part of the settlement agreement, provisions exist requiring both companies to increase funding levels for certain heating assistance programs for low-income customers. The settlement remains subject to approval by the KPSC which is expected in December 2011.

In light of the outcome of the company's 2010 rate case, the settlement reached with parties on the ECR proposal, and the menu of recovery mechanisms that exist in the state, we view the regulatory environment at the upper end of the Baa rating factor for Factor 1: Regulatory Framework within Moody's methodology, and at the lower end of the A category for Factor 2: Ability to Recover Costs and Earn Returns.

COAL-FIRED BASELOAD GENERATION, WHILE COST COMPETITIVE, EXPOSED TO FUTURE ENVIRONMENTAL REGULATION OR POLICES

Coal units account for approximately 60% of KU's owned capacity, and 98% of its generation. This significant amount of coal-fired generation exposes KU to impending legislative or regulatory policies aimed at reducing CO2 and other emissions. Our rating incorporates the view that this concentration and future exposure risk is mitigated by the ability to recover such costs under the ECR surcharge.

Moody's acknowledges that a core aspect of this concentration risk is the fact it continues to provide the modestly sized service territory with reliable, low-cost electric generation sourced in large measure by regional fuel sources.

That being said, some of LG&E's coal fleet will be shut down following existing and pending EPA regulations, which mandates reductions in NOx and SO2 emissions starting in 2012. On September 15th, LG&E and KU filed a certificate of public convenience (CPCN) for the construction of a 640-MW natural gas combined cycle facility at the Cane Run coal site. LG&E intends to shut down all three coal units at Cane Run by 2015. The companies filed their application with Louisville Metro Air Pollution Control District in June 2011 and expect the KPSC to rule on the CPCN by April 2012. Once approved, construction at Cane Run is expected to begin in 2012 and be completed by 2016, replacing all coal generation with natural gas.

Moody's observes that the EPA's revised National Ambient Air Quality Standards will further restrict NOx and SO2 emissions beginning in 2016 and 2017, which could further impact LG&E's and KU's coal generating units.

In light of this fuel concentration risk, we score KU a "B" for Factor 3: Sub-factor 2 , Generation and Fuel Diversification to reflect the lack of fuel diversification as substantially all its current generation is produced from coal-fired power plants.

EXPANDING CAPITAL EXPENDITURE PROGRAM

Capital expenditures for KU are expected to be $330 million for 2011, of which $139 million is earmarked for environmental related requirements. Capital expenditures over the next four years are expected to substantially increase to $657 million in 2012, $787 million in 2013, $789 million in 2014, and $679 million in 2015. Environmental capital expenditures represent the primary reason for the increase with such costs accounting for $440 million in 2012, $564 million in 2013, $564 million in 2014, and $428 million in 2015. The majority of these environmental capital costs are expected to be recovered under the company's ECR should the proposed settlement be approved by the KPSC.

HEALTHY FINANCIAL PROFILE

KU's financial metrics have remained relatively healthy, with a ratio of consolidated cash flow before changes in working capital (CFO pre W/C) to debt averaging nearly 19%, retained cash flow to debt averaging a healthy 18% and CFO pre-W/C interest coverage averaging 5.2 times over the past three years. While these standalone credit metrics strongly position KU in the current rating category, the rating also considers the incremental debt that exists at holding company LKE as well as the likely strain on the balance sheet given the substantial size of future capital spending. An important rating consideration will be the manner in which future capital investment is financed to include, when necessary, anticipated issuance of PPL common equity to help finance the very large amount of planned capital investment.

PPL'S ACQUISITIONS HAVE TRANSFORMED STRATEGY, LOWERING OVERALL BUSINESS RISK

PPL's acquisitions of LKE, which closed in November 2010, was followed in April 2011, with the acquisition of the Central Networks electricity distribution business (since renamed PPL WEM Holdings (PPL WEM, rated Baa3), for £3.6 billion ($5.7 billion) in cash, inclusive of certain permitted pre-closing adjustments, plus £500 million ($800 million) of existing public debt assumed through consolidation.

Completion of these two acquisitions have reduced PPL's overall business risk, making it less commodity sensitive, which we believe indirectly benefits the operations at KU. We estimate that at least 70% of consolidated results going forward will be provided by predictable, rate regulated businesses from three different jurisdictions, two of which have, in our opinion, an above-average regulatory profile. Together, we estimate that the UK and Kentucky operations alone will provide about 65% of the company's earnings and cash flow in most years.

Liquidity Profile

KU maintains a $400 million senior unsecured revolving credit facility, that expires in October 2016, of which the entire $400 million is available at September 30, 2011. The facility contains a financial covenant requiring KU's debt to total capitalization not to exceed 70%, as calculated in accordance with the credit facility. In addition, in April 2011, KU entered into an additional $198 letter of credit facility expiring in April 2014, which KU uses to support outstanding tax-exempt bonds. Additionally, KU participates in an intercompany money pool agreement whereby LKE and/or LG&E can make available to KU excess funds (up to $400 million) at market-based rates. At September 30, 2011, there was no balance outstanding under the money pool. As capital investment increases, Moody's anticipates KU being a more active short-term borrower with an eye towards permanently funding the short-term debt with periodic issuances of long-term debt and equity contributions.

At September 30, 2011, KU's tax-exempt revenue bonds that are in the form of auction rate securities and total $96 million continue to experience failed auctions. Therefore, the interest rate continues to be set by a formula pursuant to the relevant indentures. For the nine months ended September 30, 2011, the weighted-average rate on KU's auction rate bonds in total was 0.29%.

Rating Outlook

The stable outlook considers the continued above-average performance in KU's financial metrics over the near-term driven in part by credit supportive regulatory outcomes including a strong suite of recovery mechanisms. The stable outlook further considers our belief that the sizeable capital investment program will be financed in a credit benign manner to include the issuance of equity when needed.

What Could Change the Rating - Up

In light of a very large multi-year capital spending program, prospects for an upgrade may be challenging in the near-term. However, should the proposed ECR settlement be adopted and KU finances its material capital expenditures in a conservative fashion, KU's rating could be upgraded, particularly if its ratios of CFO pre-WC to debt and retained cash flow to debt exceed 22% and 17%, respectively, on a sustained basis.

What Could Change the Rating - Down

KU's ratings could be downgraded should the company encounter unexpected problems obtaining ECR cost recovery or if unanticipated changes were made to the regulatory compact that currently provides for timely recovery of costs leading to the company's ratios of CFO pre-WC to debt and retained cash flow to debt dropping below 16% and 11%, respectively.

Other Considerations

Moody's evaluates KU's consolidated financial performance relative to the Regulated Electric and Gas Utilities rating methodology published in August 2009 and as depicted in the grid below, KU's indicated rating under the grid is Baa1 on both a historical and projected basis consistent with KU's existing Baa1 Issuer Rating.

Rating Factors

Kentucky Utilities Co.

Regulated Electric and Gas Utilities Industry [1][2]	Current 12/31/2010		Moody's 12-18 month Forward View* As of June 2011	
Factor 1: Regulatory Framework (25%)	Measure	Score	Measure	Score
a) Regulatory Framework		Baa		Baa
Factor 2: Ability To Recover Costs And Earn Returns (25%)				
a) Ability To Recover Costs And Earn Returns		A		A
Factor 3: Diversification (10%)				
a) Market Position (5%)		Baa		Baa
b) Generation and Fuel Diversity (5%)		Ba		Ba
Factor 4: Financial Strength, Liquidity And Key Financial Metrics (40%)				
a) Liquidity (10%)		A		A

b) CFO pre-WC + Interest/ Interest (3 Year Avg) (7.5%)	5.2x	A	5-6.5x	A
c) CFO pre-WC / Debt (3 Year Avg) (7.5%)	18.7%	Baa	18-22%	Baa
d) CFO pre-WC - Dividends / Debt (3 Year Avg) (7.5%)	17.9%	A	14-18%	A
e) Debt/Capitalization (3 Year Avg) (7.5%)	43.6%	A	40-45%	A
Rating:				
a) Indicated Rating from Grid		Baa1		Baa1
b) Actual Rating Assigned		Baa1		Baa1

* THIS REPRESENTS MOODY'S FORWARD VIEW; NOT THE VIEW OF THE ISSUER; AND UNLESS NOTED IN THE TEXT DOES NOT INCORPORATE SIGNIFICANT ACQUISITIONS OR DIVESTITURES

[1] All ratios are calculated using Moody's Standard Adjustments. [2] As of 12/31/2010(L); Source: Moody's Financial Metrics

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Kentucky Utilities Company
($ Thousands, as Adjusted)

	2006	2007	2008	2009	LTM3Q10
Interest Expense	$43,905	$59,232	$83,044	$83,950	$85,835
CFO	$227,000	$318,000	$298,000	$266,667	$376,667
Change in w/c	$(46,000)	$(1,000)	$(10,000)	$(87,000)	$(72,000)
CFO-w/c	$273,000	$319,000	$308,000	$353,667	$448,667
Change in other A&L	$(25,000)	$(6,000)	$(5,000)	$7,000	$104,000
FFO	$298,000	$325,000	$313,000	$346,667	$344,667
Dividends	$-	$-	$-	$-	$(50,000)
CFO-w/c-dividends	$273,000	$319,000	$308,000	$353,667	$398,667
RCF (FFO-Div)	$298,000	$325,000	$313,000	$346,667	$294,667
CapEx	$(351,000)	$(749,000)	$(692,000)	$(522,667)	$(362,667)
FCF	$(124,000)	$(431,000)	$(394,000)	$(256,000)	$(36,000)
As Rpt STD	$97,000	$23,000	$16,000	$45,000	$61,000
As Rpt Gross Debt	$843,000	$1,264,000	$1,532,000	$1,682,000	$1,682,000
As Rpt Total Debt	$940,000	$1,287,000	$1,548,000	$1,727,000	$1,743,000
Change in Debt		$347,000	$261,000	$179,000	$16,000
Pension Adjustment	$50,000	$20,000	$123,000	$97,000	$97,000
Lease Adjustment	$36,000	$36,000	$54,000	$60,000	$60,000
Other Adjustment	$-	$-	$-	$-	$-
Total Adjustments	$86,000	$56,000	$177,000	$157,000	$157,000
Total Adj Debt	$1,026,000	$1,343,000	$1,725,000	$1,884,000	$1,900,000
Minority Interest	$-	$-	$-	$-	$-
Total Adj Equity	$1,193,000	$1,435,000	$1,744,000	$1,952,000	$2,029,000
Deferred Tax Liability (LT)	$289,000	$285,000	$279,000	$336,000	$378,000
Total Adj Capitalization	$2,508,000	$3,063,000	$3,748,000	$4,172,000	$4,307,000
(CFO-w/c + Interest) / Interest	7.2x	6.4x	4.7x	5.2x	6.2x
(CFO-w/c) / Debt	26.6%	23.8%	17.9%	18.8%	23.6%
FFO / Debt	29.0%	24.2%	18.1%	18.4%	18.1%
(CFO-w/c - Dividends) / Debt	26.6%	23.8%	17.9%	18.8%	21.0%
RCF / Debt	29.0%	24.2%	18.1%	18.4%	15.5%
Debt / Capitalization	40.9%	43.8%	46.0%	45.2%	44.1%
FCF / Debt	-12.1%	-32.1%	-22.8%	-13.6%	-1.9%

Moody's Investors Service

Global Credit Research
Credit Opinion
29 JAN 2010

Credit Opinion: Kentucky Utilities Co.

Kentucky Utilities Co.

Lexington, Kentucky, United States

Ratings

Category	Moody's Rating
Outlook	Stable
Issuer Rating	A2
Ult Parent: E.ON AG	
Outlook	Stable
Senior Unsecured -Dom Curr	A2
Commercial Paper	P-1
Parent: E. ON U.S. LLC	
Outlook	Stable
Issuer Rating	A3

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Opinion

Rating Drivers

E.ON AG ownership strengthens KU's financial position

Regulatory compact allows for the timely recovery of costs

Elevated capital expenditure spending program

Ability to manage a successful outcome for a recently filed rate case

Corporate Profile

Kentucky Utilities (KU) is a regulated public utility engaged in the generation, transmission and distribution of electricity. It provides electricity to approximately 512,000 customers in 77 counties in central, southeastern and western Kentucky and to approximately 30,000 customers in 5 counties in southwestern Virginia and 5 customers in Tennessee. KU's coal-fired electric generating plants produce approximately 99% of its electricity with the remainder 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. The company also sells wholesale electric energy to 12 municipalities.

KU is a wholly-owned subsidiary of E.ON U.S. LLC (A3 Issuer Rating). E.ON U.S. is an indirect wholly-owned subsidiary of E.ON AG (A2 senior unsecured). KU's affiliate Louisville Gas and Electric Company (LG&E; A2 Issuer Rating), is a regulated public utility also operating in Kentucky. Although LG&E and KU are separate legal entities, they are operated as a single, fully integrated system and provide the majority of the consolidated earnings and cash flow of E.ON U.S. LLC.

SUMMARY RATING RATIONALE

Moody's evaluates KU's consolidated financial performance relative to the Regulated Electric and Gas Utilities rating methodology published in August 2009 and as depicted in the grid below, KU's indicated rating under this methodology is A3 compared to its A2 senior unsecured rating.

KU receives a one notch rating lift from its ownership by E.ON AG. Specifically, E.ON AG's size, scale and credit profile has historically provided KU considerable liquidity and financial flexibility primarily in the form of inter-company funding and a liberal dividend policy that in our opinion considerably strengthens KU's financial position. Inter-company debt accounted for approximately 80% of KU's approximate $1.7 billion of debt at September 30, 2009.

The rating and outlook of KU could be affected if E.ON AG's senior unsecured rating were to be pressured.

In addition to its ownership by E.ON AG, KU's A2 senior unsecured rating reflects its historical financial metrics combined with regulatory supportiveness provided by the Kentucky Public Service Commission (KPSC) and its historical ability to recover costs in a timely manner.

STRONG FINANCIAL PROFILE AND CONSERVATIVE FINANCIAL POLICY

While down slightly from prior levels due primarily to inter-company debt incurred to fund its environmental spending requirements and construction of its Trimble 2 generating facility, KU's key financial metrics remain within a notch or two of its current rating. Specifically, KU's ratio of consolidated cash flow before changes in working capital (CFO pre W/C) to debt and CFO pre-W/C interest coverage for the twelve months ended September 30, 2009 were approximately 18% and 4.5 times, respectively.

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 $62 million of incremental operation and maintenance expenses related to the restoration following the two storms. KU has been allowed by the KPSC to establish a regulatory asset for its 2009 storm costs and has requested recovery of these costs. In September 2009, the company recognized a regulatory asset of $57 million for actual costs incurred.

KU's rating is notched upward to reflect the benefits associated with its ownership by E.ON AG. The benefits include inter-company funding support and a dividend policy that has not required KU to make any dividend payments since its capital spending requirements began to ramp up in 2005. Rather, KU has received equity contributions during this timeframe in order to maintain an approximate 53% equity capitalization.

CONSTRUCTIVE REGULATORY ENVIRONMENT

KU has an environmental cost recovery mechanism in its electric rates that allow for the recovery of environmental costs, including a 10.63% return on equity. This is an important factor given that KU and LG&E's combined environmental capital spending has been estimated to be approximately $700 million in aggregate during the three-year period ending 2011. Proceedings are conducted every two years to evaluate the operation of the environmental cost recovery mechanism. The utilities also benefit from a fuel adjustment clause that eliminates supply cost volatility.

KU filed a rate case in January 2010 requesting a $135 million or 11.5% base electric rate increase with a proposed effective date of March 1, 2010. The rate increase is needed to cover increased costs, to provide a return on the company's considerable investments in its infrastructure, primarily the new 750MW Trimble 2 coal plant, and to recover costs associated with storm restorations. The KPSC has the ability to suspend the proposed rate increase for up to 6 months. The current weak statewide economic environment could present a challenge for KU in its efforts to manage a successful rate outcome

LARGE CAPITAL EXPENDITURE PROGRAM

The company is nearing construction completion of the Trimble 2 generating station of which LG&E and KU own undivided 14.25% and 60.75% interests, respectively. The remaining 25% interest is owned by regional municipal power entities. The generating station is expected to begin commercial operation during the summer of 2010 at a total cost to KU and LG&E of approximately $900 million.

KU's capital expenditures are expected to still remain significant going forward, estimated at $1,300 million for the three year period ending December 31, 2011. Incremental inter-company funding is anticipated in order to finance in part these expenditures. KU's capital expenditures totaled $378 million for nine months ended September 30, 2009 and $690 million for FY 2008.

Liquidity

KU's external sources for liquidity includes a $35 million bilateral line of credit with a third party lender due June 2012 and an inter-company money pool agreement where E.ON U.S. and/or LG&E make up to $400 million of funds available to KU. KU's borrowing under the inter-company money pool at September 30, 2009 was $23 million. There were no borrowings under the bilateral line of credit, which is used to backstop a similar amount of pollution control revenue bonds that are subject to tender for purchase at the option of the holder.

E.ON U.S. maintains revolving credit facilities totaling $313 million at September 30, 2009 with an affiliated company to ensure funding availability for the money pool.

Rating Outlook

The stable rating outlook reflects Moody's expectation that KU will continue to show strong fundamentals and that inter-company funding support will continue to be provided by E.ON AG.

What Could Change the Rating - Up

In light of KU's sizeable expenditure program, limited prospects exist for the rating to be upgraded over the next several years. Longer-term, core financial metrics would need to improve considerably, such as CFO pre W/C to debt greater than 30%, for Moody's to consider an upgrade.

What Could Change the Rating - Down

Moody's would consider a rating downgrade if E. ON AG's senior unsecured rating was downgraded from its current A2 level, if inter-company funding support was discontinued or significant changes were made to the environmental cost recovery mechanism or if CFO pre-W/C declined to below 15%.

Rating Factors

Kentucky Utilities Co.

Regulated Electric and Gas Utilities	Aaa	Aa	A	Baa	Ba	B
Factor 1: Regulatory Framework (25%)				X		
Factor 2: Ability to Recover Costs and Earn Returns (25%)			X			
Factor 3: Diversification (10%)						
a) Market Position (5%)				X		
b) Generation and Fuel Diversity (5%)					X	
Factor 4: Financial Strength, Liquidity and Key Financial Metrics (40%)						
a) Liquidity (10%)			X			
b) CFO pre-WC + Interest / Ineterest (7.5%) (3yr Avg)		X				
c) CFO pre-WC / Debt (7.5%) (3yr Avg)			X			
d) CFO pre-WC - Dividends / Debt (7.5%) (3yr Avg)			X			
e) Debt / Capitalization or Debt / RAV (7.5%) (3yr Avg)			X			
Rating:						
a) Methodology Implied Senior Unsecured Rating				A3		
b) Actual Senior Unsecured Rating				A2		

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Moody's Investors Service

Global Credit Research

Credit Opinion

3 MAR 2006

Credit Opinion: Kentucky Utilities Co.

Kentucky Utilities Co.

Lexington, Kentucky, United States

Ratings

Category	Moody's Rating
Outlook	Stable
Issuer Rating	A2
First Mortgage Bonds	A1
Senior Secured Shelf	(P)A1
Ult Parent: E.ON AG	
Outlook	Rating(s) Under Review
Bkd Sr Unsec Bank Credit Facility -Dom Curr	*Aa3
Senior Unsecured MTN -Dom Curr	*Aa3
Commercial Paper -Dom Curr	Aa3
Parent: E. ON U.S. LLC	
Outlook	Stable
Issuer Rating	A3

* Placed under review for possible downgrade on February 22, 2006

Contacts

Analyst	Phone
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Richard E. Donner/New York	
Daniel Gates/New York	

Key Indicators

Kentucky Utilities Co.

	LTM 9/2005	2004	2003
Funds from Operations / Adjusted Debt	26.6%	32.8%	31.6%
Retained Cash Flow / Adjusted Debt	18.1%	24.1%	31.6%
Common Dividends / Net Income Available for Common	56.5%	47.2%	0.0%
Adjusted Funds from Operations+Adj. Interest / Adj. Interest	7.51	9.35	9.19
Adjusted Debt / Adjusted Capitalization	44.7%	41.9%	43.5%
Net Income Available for Common / Common Equity	12.8%	13.8%	10.1%

Note: For definitions of Moody's most common ratio terms please see the accompanying User's Guide.

Opinion

Credit Strengths

Kentucky Utilities Company's credit strengths include:

Strong financial profile;

Solid track record of managing costs, maintaining low rates and focusing on customer satisfaction;

Stable, supportive regulatory environment.

Credit Challenges

Kentucky Utilities Company's credit challenges include:

Possibility that senior unsecured rating of the ultimate parent company E. ON AG may decline to a level equal to or below the rating of KU's direct parent E. ON U.S LLC.

Supporting the increasing native load requirements;

Managing environmental and regulatory capital requirement;

Rating Rationale

Kentucky Utilities Company's (KU) A2 Issuer Rating is based on the utility's strong financial profile, favorable cost positions and balanced regulatory environments.

The ratings of KU were affirmed following the action that placed the ratings of the ultimate parent company E. ON AG under review for possible downgrade upon the announcement of its cash offer to acquire 100% of the equity interest in Endesa SA for approximately $35 billion plus assumption of about $31 billion existing debts. Moody's indicated that, while the magnitude of any downgrade can only be assessed when the transaction price is finalized, the most likely rating outcome for E. ON AG would be a senior unsecured debt rating that is weakly positioned at A2, if the acquisition offer were to be successful.

KU receives intercompany funding support provided by E. ON AG and its affiliated companies and benefits from advantegeous borrowing terms. KU's financial focus is supported by a demonstrated record of cost control, productivity enhancements, network service performance, a focus on customer satisfaction and a balanced regulatory environment. KU and its affiliate, Louisville Gas & Electric (A2 Issuer Rating), enjoy an environmental cost recovery mechanism in their electric rates that allows for the recovery of environmental costs associated with meeting its obligations under federal and state statutes and a fuel adjustment clause that eliminates supply cost volatility. Over the next few years, the challenges ahead for both utilities include supporting the level of demand in the service territory and maintaining an adequate reserve margin.

Although LG&E and KU are separate legal entities, they are operated as a single, fully integrated system and provide the majority of the consolidated earnings and cash flow of E.ON U.S. LLC.

Rating Outlook

The stable rating outlook reflects Moody's expectation that KU will continue to show strong fundamentals.

What Could Change the Rating - UP

With E. ON AG's offer for Endesa, Moody's does not see any likely upward rating pressure.

What Could Change the Rating - DOWN

Moody's would consider a rating downgrade if E. ON AG's senior unsecured rating were to decline to a level equal to or below the ratings of US entities as a result of the acquisition of Endesa, or significant changes were made to the environmental cost recovery mechanism.

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Prepared for John Early

All figures quoted in millions based on entities' current reporting currency

Kentucky Utilities Co. (BBB/Watch Pos/A-2)

Business Description*

Kentucky Utilities Company, a regulated utility, is engaged in the generation, transmission, distribution, and sale of electricity in Kentucky, Virginia, and Tennessee. The company serves its Virginia customers under the Old Dominion Power name; and its Kentucky and Tennessee customers under the KU name. It generates electricity coal, oil, gas, and hydro sources. As of December 31, 2013, the company had 4,739 megawatts of electric power generation capacity. Its transmission system included 137 substations with a total capacity of 14 million kilovolt-ampere (kVA) and 4,079 pole miles of lines; and distribution system comprised 480 substations with capacity of 7 million kVA, 14,134 circuit miles of overhead lines, and 2,288 miles of underground conduit cable miles. The company provides electric services to approximately 514,000 customers in 77 counties in central, southeastern, and western Kentucky; approximately 29,000 customers in five counties in southwestern Virginia; and approximately ten customers in Tennessee. It also sells wholesale electricity to 12 municipalities in Kentucky under load following contracts. The company was incorporated in 1912 and is headquartered in Lexington, Kentucky. Kentucky Utilities Company is a subsidiary of LG&E and KU Energy LLC.

Major Rating Factors*

Strengths:

- Stable and predictable cash flows;
- Credit-supportive regulatory environment in Kentucky;
- Competitive rates; and
- Efficient operations and high customer satisfaction ratings.

Weaknesses:

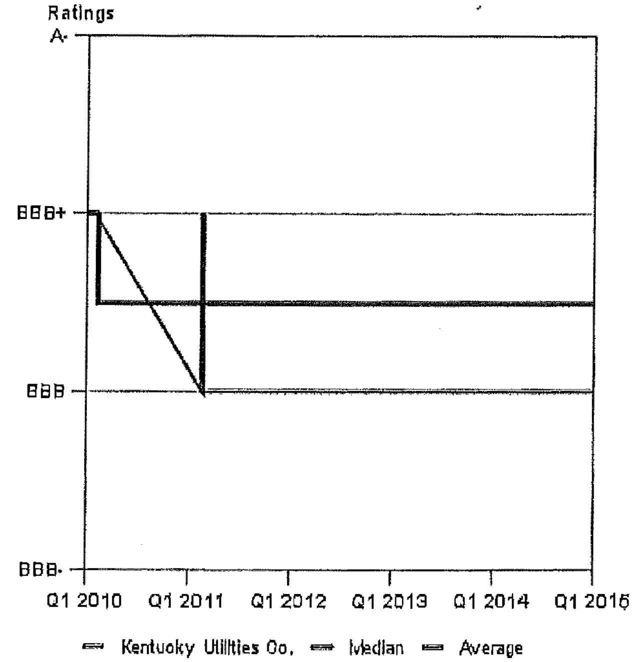
- Little fuel diversity, the company's plants are virtually all coal-fired;
- Exposure to pending environmental standards; and
- Linked to parent credit quality.

Issuer Credit Measures (as of February 07, 2015)				
S&P Issuer Credit Rating	Rating Date	Rating	CreditWatch/Outlook	CreditWatch/Outlook Date
Foreign Currency LT	02-Mar-2011	BBB	Watch Pos	10-Jun-2014
Foreign Currency ST	15-Apr-2011	A-2		
Local Currency LT	02-Mar-2011	BBB	Watch Pos	10-Jun-2014
Local Currency ST	15-Apr-2011	A-2		

Kentucky Utilities Co.		BBB/Watch Pos/A-2	USD in Millions	
Sub-sector: Utilities	Industry: Electric	[1]CDS: —	[1]CDS 90 day Hi/Lo: —	[1]CDS-MDS: —
Rev: 1,730.00	EBITDA: 662.14	Debt/EBITDA: 3.68x	EBITDA Int Cov: 7.21x	

Analytical Contacts: S&P Primary Analyst - Dimitri Nikas, New York (1 212-438-7807) & S&P Backup Analyst - Gerrit W Jepsen, CFA, New York (1 212-438-7807)

Foreign Currency LT Ratings History (Last 5 Years)



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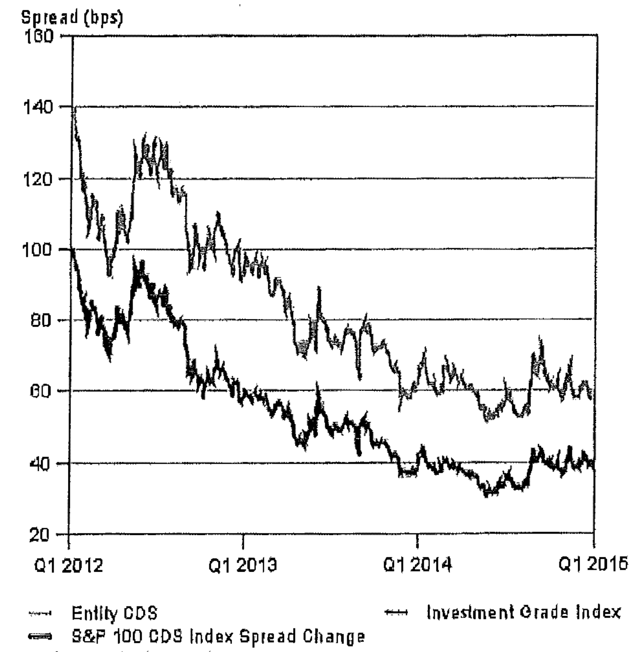
Credit Default Swap History (Last 3 Years)



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[1]CDS Data provided by CMA DataVision as of previous day closing values, EST.

Peer Group: Ratings Comparison — Global Electric Companies — Updated As of February 07, 2015

Rank	Issuers	ICR	ICR Date	Previous ICR	Previous ICR Date	CDS(bps)	MDS
1	EPCOR Utilities Inc.	A-/Stable/--	26-Sep-2014	BBB+/Positive/--	25-Jul-2013		
2	Interstate Power & Light Co.	A-/Stable/A-2	11-Jan-2013	BBB+/Stable/A-2	24-Jan-2012		
3	Southwestern Public Service Co.	A-/Stable/A-2	23-Jun-2010	BBB+/Positive/A-2	10-Jun-2009		
4	Kansas City Power & Light Co.	BBB+/Stable/A-2	01-May-2014	BBB/Positive/A-2	24-Apr-2013		
5	Potomac Electric Power Co.	BBB+/Stable/A-2	01-Jul-2010	BBB/Watch Pos/A-2	21-Apr-2010		
6	Kentucky Utilities Co.	BBB/Watch Pos/A-2	10-Jun-2014	BBB/Stable/A-2	15-Apr-2011		
7	PPL Electric Utilities Corp.	BBB/Watch Pos/A-2	10-Jun-2014	BBB/Stable/A-2	15-Apr-2011		
8	Portland General Electric Co.	BBB/Stable/A-2	29-Jan-2010	BBB+/Negative/A-2	29-Jan-2009		
9	Southwestern Electric Power Co.	BBB/Positive/--	29-Sep-2014	BBB/Stable/--	07-Mar-2003		
10	Jersey Central Power & Light Co.	BBB-/Stable/NR	11-Feb-2010	BBB/Stable/NR	01-Aug-2008		
11	Ohio Edison Co.	BBB-/Stable/A-3	11-Feb-2010	BBB/Stable/A-2	01-Aug-2008		

Kentucky Utilities Co.		BBB/Watch Pos/A-2	USD in Millions	
Sub-sector: Utilities	Industry: Electric	¹CDS: —	¹CDS 90 day Hi/Lo: —	¹CDS-MDS: —
Rev: 1,730.00	EBITDA: 662.14	Debt/EBITDA: 3.68x	EBITDA Int Cov: 7.21x	

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Peer Group: Financial Comparison — Global Electric Companies — Updated As of February 07, 2015

	Profitability						Leverage	Debt Servicing	
Issuers	Revenue	EBITDA	Cash Flow From Ops.	CAPEX	FOCF	Op. Inc./ Rev. (%)	Debt/ EBITDA (x)	EBITDA Int. Cov. (x)	FOCF/ Debt (%)
Potomac Electric Power Co. (30-Sep-2014)*	2,105.00	575.50	425.35	547.25	(121.90)	27.34	3.85	4.71	(5.51)
PPL Electric Utilities Corp. (30-Sep-2014)*	1,997.00	701.13	647.32	979.00	(331.68)	34.68	3.93	5.16	(12.05)
Jersey Central Power & Light Co. (30-Sep-2014)*	1,877.00	542.50	235.64	232.00	3.64	28.90	4.36	3.53	0.15
Portland General Electric Co. (30-Sep-2014)*	1,899.00	647.12	545.95	1,029.85	(483.91)	33.87	4.13	4.60	(18.12)
Southwestern Electric Power Co. (30-Sep-2014)*	1,850.02	523.05	515.98	508.42	7.56	28.27	4.48	5.08	0.32
Kentucky Utilities Co. (30-Sep-2014)*	1,730.00	662.14	577.25	761.00	(183.75)	38.27	3.68	7.21	(7.54)
Interstate Power & Light Co. (30-Sep-2014)*	1,880.10	436.35	332.01	485.90	(153.89)	22.87	4.05	4.04	(8.71)
Ohio Edison Co. (30-Sep-2014)*	1,629.00	665.50	238.84	161.00	77.84	40.85	2.05	5.35	5.71
Kansas City Power & Light Co. (30-Sep-2014)*	1,735.60	580.00	504.65	602.40	(97.75)	33.07	4.78	3.83	(3.53)
EPCOR Utilities Inc. (30-Sep-2014)*	1,697.43	419.21	304.05	346.29	(42.23)	23.75	4.61	3.46	(2.19)
Southwestern Public Service Co. (30-Sep-2014)*	1,883.31	434.61	338.18	563.43	(225.25)	23.08	3.87	3.68	(13.39)
Peer Group Average	**1,843.97**	**562.46**	**424.11**	**565.14**	**(141.03)**	**30.45**	**3.98**	**4.60**	**(5.90)**

** LTM as of*

All figures quoted in millions USD , based on the issuers base currency.

Peer Group: CreditStats Direct Comparison — Global Electric Companies — Updated As of February 07, 2015

	2013	2013 vs Peers	2012	2012 vs Peers	2011	2011 vs Peers	2010	2010 vs Peers	2009	2009 vs Peers
Revenue	1,635.00	1,785.09	1,524.00	1,721.39	1,548.00	1,804.39	1,511.00	1,887.82	1,355.00	2,003.73
EBITDA	637.14	539.68	530.40	492.15	563.40	484.63	517.50	506.58	430.00	500.62
Cash Flow From Operations	515.45	362.64	517.59	415.03	465.67	360.68	379.82	361.24	258.60	332.07
CAPEX	856.82	542.95	498.90	426.65	283.34	352.98	384.01	345.97	521.60	435.17
Free Operating Cash Flow	(341.37)	(180.31)	18.70	(11.62)	182.33	7.71	(4.19)	15.27	(263.00)	(103.10)
Annual Revenue Growth (%)	7.28	4.72	(1.55)	(4.16)	2.45	(1.68)	11.51	(3.38)	(3.49)	(5.65)
Debt/EBITDA (x)	3.86	4.00	4.00	4.10	3.61	3.88	3.97	3.79	4.44	3.78
Operating Income (BefD&A)/Revenue (%)	38.97	30.07	34.80	28.59	36.40	26.86	34.25	26.84	31.73	25.65
EBITDA/Interest (x)	8.84	5.12	7.39	4.83	7.70	4.84	6.35	5.01	5.36	5.08

Kentucky Utilities Co.		BBB/Watch Pos/A-2	USD in Millions	
Sub-sector: Utilities	Industry: Electric	[1]CDS: —	[1]CDS 90 day Hi/Lo: —	[1]CDS-MDS: —
Rev: 1,730.00	EBITDA: 662.14	Debt/EBITDA: 3.68x	EBITDA Int Cov: 7.21x	

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Peer Group: CreditStats Direct Comparison — Global Electric Companies — Updated As of February 07, 2015

	2013	2013 vs Peers	2012	2012 vs Peers	2011	2011 vs Peers	2010	2010 vs Peers	2009	2009 vs Peers
FOCF/Debt (%)	(16.06)	(9.70)	1.05	(0.42)	8.96	0.36	(0.38)	(0.17)	(15.23)	(5.64)

Adjusted Income statement as of December 02, 2014

	Annual 31-Dec-2013 USD	Annual 31-Dec-2012 USD	Annual 31-Dec-2011 USD	Annual 31-Dec-2010 USD	Annual 31-Dec-2009 USD
Sales	1,635.00	1,524.00	1,548.00	1,511.00	1,355.00
Other operating revenues	—	—	—	—	—
Revenues, pre-adjusted	**1,635.00**	**1,524.00**	**1,548.00**	**1,511.00**	**1,355.00**
Less: Captive finance revenues	0.00	0.00	0.00	0.00	0.00
Plus: Revenues, consolidating (deconsolidating)	—	—	—	—	—
Less: Nonrecourse interest	0.00	0.00	0.00	0.00	0.00
Less: Securitized interest	0.00	0.00	0.00	0.00	0.00
Less: Amortized portion of nonrecourse debt	0.00	0.00	0.00	0.00	0.00
Less: Amortized portion of securitized debt	0.00	0.00	0.00	0.00	0.00
Plus: Revenues - Finance/Interest Income	—	—	—	—	—
Plus: Revenues - Profit on disposals	—	—	—	—	—
Plus: Revenues - Derivatives	—	—	—	—	—
Revenue - Other	—	—	—	—	—
Revenues, adjusted	**1,635.00**	**1,524.00**	**1,548.00**	**1,511.00**	**1,355.00**
Cost of goods sold	610.00	607.00	628.00	670.00	633.00
SG&A	—	—	—	—	—
R&D	—	—	—	—	—
Raw materials, supplies, and merchandise	—	—	—	—	—
Change in stocks	0.00	0.00	0.00	0.00	0.00
Capitalized costs	0.00	0.00	0.00	0.00	0.00
Staff expense, total	—	—	—	—	—
Taxes other than income	24.00	23.00	19.00	—	—
Operating expense, other	382.00	384.00	362.00	346.00	320.00
Income (expense) of unconsolidated companies	0.00	0.00	0.00	0.00	0.00
Special items (disposals, restructuring, FX, asset sales)	0.00	0.00	0.00	0.00	0.00
Total operating expense (bef. D& A), pre-adjusted	**1,016.00**	**1,014.00**	**1,009.00**	**1,016.00**	**953.00**
Operating income (bef. D&A), pre-adjusted	**619.00**	**510.00**	**539.00**	**495.00**	**402.00**
Plus: Trade receivables sold	—	—	—	—	—
Plus: OLA rent	9.50	9.00	8.50	7.50	8.00

Kentucky Utilities Co.		BBB/Watch Pos/A-2	USD in Millions	
Sub-sector: Utilities	Industry: Electric	[1]CDS: —	[1]CDS 90 day Hi/Lo: —	[1]CDS-MDS: —
Rev: 1,730.00	EBITDA: 662.14	Debt/EBITDA: 3.68x	EBITDA Int Cov: 7.21x	

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Adjusted Income statement as of December 02, 2014

	Annual 31-Dec-2013 USD	Annual 31-Dec-2012 USD	Annual 31-Dec-2011 USD	Annual 31-Dec-2010 USD	Annual 31-Dec-2009 USD
Less: Captive finance revenues	0.00	0.00	0.00	0.00	0.00
Plus: Captive finance operating expense	0.00	0.00	0.00	0.00	0.00
Plus: Revenues, consolidating (deconsolidating)	—	—	—	—	—
Less: Expenses, consolidating (deconsolidating)	0.00	0.00	0.00	0.00	0.00
Less: Nonrecourse interest	0.00	0.00	0.00	0.00	0.00
Less: Securitized interest	0.00	0.00	0.00	0.00	0.00
Less: Amortized portion of nonrecourse debt	0.00	0.00	0.00	0.00	0.00
Less: Amortized portion of securitized debt	0.00	0.00	0.00	0.00	0.00
Plus: ARO finance costs	4.00	3.00	3.00	0.00	2.00
Plus: PPA depreciation	—	—	—	—	—
Plus: PPA interest expense	0.00	0.00	0.00	0.00	0.00
Less: Capitalized development costs	0.00	0.00	0.00	0.00	0.00
Less: Infrastructure renewal costs	0.00	0.00	0.00	0.00	0.00
Plus: Capitalized interest (EBITDA transfer from inventory)	—	—	—	—	—
Plus: Pension & other postretirement expense	4.64	8.40	12.90	15.00	18.00
Plus: Revenues - Finance/Interest Income	—	—	—	—	—
Plus: Revenues - Profit on disposals	—	—	—	—	—
Plus: Revenues - Derivatives	—	—	—	—	—
Revenue - Other	—	—	—	—	—
Plus: COGS- Restructuring costs	—	—	—	—	—
Plus: COGS- Valuation gains/(losses)	—	—	—	—	—
Plus: COGS- Other non-operating nonrecurring items	—	—	—	—	—
Plus: COGS- LIFO Liquidation gains	—	—	—	—	—
Plus: SG& A- Restructuring costs	—	—	—	—	—
Plus: SG& A- Valuation gains/(losses)	—	—	—	—	—
Plus: SG& A- Other non-operating nonrecurring items	—	—	—	—	—
Plus: R& D- Restructuring costs	—	—	—	—	—

Kentucky Utilities Co. BBB/Watch Pos/A-2 USD In Millions

Adjusted Income statement as of December 02, 2014

	Annual 31-Dec-2013 USD	Annual 31-Dec-2012 USD	Annual 31-Dec-2011 USD	Annual 31-Dec-2010 USD	Annual 31-Dec-2009 USD
Plus: R& D- Valuation gains/(losses)	—	—	—	—	—
Plus: R& D- Other non-operating nonrecurring items	—	—	—	—	—
Plus: RMS& M- Restructuring costs	—	—	—	—	—
Plus: RMS& M Valuation gains/(losses)	—	—	—	—	—
Plus: RMS& M- Other non-operating nonrecurring items	—	—	—	—	—
Plus: Staff - Restructuring costs	—	—	—	—	—
Plus: Staff - Valuation gains/(losses)	—	—	—	—	—
Plus: Staff - Other non-operating nonrecurring items	—	—	—	—	—
Plus: EBITDA - Income (expense) of unconsolidated companies	—	—	—	—	—
Plus: EBITDA - Gain/(Loss) on disposals of PP&E	—	—	—	—	—
Plus: EBITDA - Fair value changes of contingent consideration	—	—	—	—	—
Plus: EBITDA - Foreign Exchange gain/(loss)	—	—	—	—	—
Plus: EBITDA - Restructuring costs	—	—	—	—	—
Plus: EBITDA - Derivatives	—	—	—	—	—
Plus: EBITDA - Streaming transactions	—	—	—	—	—
Plus: EBITDA - Settlement (litigation/insurance) costs	—	—	—	—	—
Plus: EBITDA - Valuation gains/(losses)	—	—	—	—	—
Plus: EBITDA - Business Divestments	—	—	—	—	—
Plus: EBITDA - Inventory	—	—	—	—	—
Plus: EBITDA - Other income/(expense)	—	—	—	—	—
Plus: EBITDA - Other	—	—	—	—	—
Operating income (bef. D& A), adjusted	**637.14**	**530.40**	**563.40**	**517.50**	**430.00**
Impairment charges/(reversals)	—	—	—	—	—
Asset valuation gains/(losses)	0.00	0.00	0.00	0.00	0.00
D& A	186.00	193.00	186.00	145.00	133.00
D&A, Impairment & Valuation changes, pre-adjusted	**186.00**	**193.00**	**186.00**	**145.00**	**133.00**

Kentucky Utilities Co.		BBB/Watch Pos/A-2	USD In Millions	
Sub-sector: Utilities	Industry: Electric	[1]CDS: —	[1]CDS 90 day Hi/Lo: —	[1]CDS-MDS: —
Rev: 1,730.00	EBITDA: 662.14	Debt/EBITDA: 3.68x	EBITDA Int Cov: 7.21x	

Analytical Contacts: S&P Primary Analyst - Dimitri Nikas, New York (1 212-438-7807) & S&P Backup Analyst - Gerrit W Jepsen, CFA, New York (1 212-438-7807)

Adjusted Income statement as of December 02, 2014

	Annual 31-Dec-2013 USD	Annual 31-Dec-2012 USD	Annual 31-Dec-2011 USD	Annual 31-Dec-2010 USD	Annual 31-Dec-2009 USD
Plus: OLA depreciation	6.92	6.66	6.72	5.82	6.27
Less: Captive Finance depreciation	0.00	0.00	0.00	0.00	0.00
Plus: Depreciation, consolidating (deconsolidating)	—	—	—	—	—
Less: Amortized portion of nonrecourse debt	0.00	0.00	0.00	0.00	0.00
Less: Amortized portion of securitized debt	0.00	0.00	0.00	0.00	0.00
Plus: PPA depreciation	—	—	—	—	—
Less: Amortized development costs	0.00	0.00	0.00	0.00	0.00
Less: Infrastructure renewal costs	0.00	0.00	0.00	0.00	0.00
Plus: D&A - Asset Valuation gains/(losses)	—	—	—	—	—
Plus: D&A - Impairment charges/(reversals)	—	—	—	—	—
Plus: D&A - Reverse Goodwill amortisation	—	—	—	—	—
Plus: D& A - Other	—	—	—	—	—
D&A, adjusted	**192.92**	**199.66**	**192.72**	**160.82**	**139.27**
Operating income (after D&A), adjusted	**444.23**	**330.74**	**370.68**	**366.68**	**290.73**
Non-operating income (expense), total	(3.00)	(8.00)	(1.00)	1.00	6.00
EBIT, pre-adjusted	**430.00**	**309.00**	**352.00**	**351.00**	**275.00**
Plus: EBIT - Finance/Interest income	—	—	—	—	—
Plus: EBIT - Income (expense) of unconsolidated companies	—	—	—	—	—
Plus: EBIT - Other	—	—	—	—	—
Less: Captive Finance investment income	0.00	0.00	0.00	0.00	0.00
Plus: Non-operating income/(expense), consolidating (deconsolidating)	—	—	—	—	—
Plus: Transfer pmt. (to) from captive fin. co.	0.00	0.00	0.00	0.00	0.00
EBIT, adjusted	**441.23**	**322.74**	**369.68**	**367.68**	**296.73**
Interest expense, pre-adjusted	**70.00**	**69.00**	**70.00**	**78.00**	**76.00**
Plus: Capitalized interest	0.00	0.00	0.00	0.00	0.00
Capitalized interest not in capex (some IFRS credits)	—	—	—	—	—
Plus: OLA interest expense	2.58	2.34	1.78	1.68	1.73
Plus: Interest from receivables sold	0.00	0.00	0.00	0.00	0.00

Kentucky Utilities Co. BBB/Watch Pos/A-2 USD In Millions

Sub-sector: Utilities Industry: Electric ¹CDS: — ¹CDS 90 day Hi/Lo: — ¹CDS-MDS: —

Rev: 1,730.00 EBITDA: 662.14 Debt/EBITDA: 3.68x EBITDA Int Cov: 7.21x

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Adjusted Income statement as of December 02, 2014

	Annual 31-Dec-2013 USD	Annual 31-Dec-2012 USD	Annual 31-Dec-2011 USD	Annual 31-Dec-2010 USD	Annual 31-Dec-2009 USD
Plus: receivables sold interest adjustment	—	—	—	—	—
Less: Captive finance interest	0.00	0.00	0.00	0.00	0.00
Plus: Interest expense, consolidating (deconsolidating)	—	—	—	—	—
Plus: PPA interest expense	0.00	0.00	0.00	0.00	0.00
Plus: ARO finance costs	4.00	3.00	3.00	0.00	2.00
Less: Nonrecourse interest	0.00	0.00	0.00	0.00	0.00
Less: Securitized interest	0.00	0.00	0.00	0.00	0.00
Plus: Low equity hybrid dividend accrual	—	—	—	—	—
Less: High equity hybrid interest expense	0.00	0.00	0.00	0.00	0.00
Less: Intermediate-equity hybrid interest expense	0.00	0.00	0.00	0.00	0.00
Plus: Intermediate-equity hybrid dividend accrual	0.00	0.00	0.00	0.00	0.00
Plus: Pension & Other postretirement interest expense	1.68	6.74	7.91	9.92	11.03
Plus: Interest expense - Derivatives	—	—	—	—	—
Plus: Interest expense - Shareholder loan	—	—	—	—	—
Plus: Interest - Streaming transactions	—	—	—	—	—
Plus: Interest expense - Other	1.82	1.82	1.82	1.82	1.70
Interest expense, adjusted	**80.09**	**82.90**	**84.52**	**91.43**	**91.47**
	—	—	—	—	—
EBITDA, pre-adjusted	**619.00**	**610.00**	**539.00**	**495.00**	**402.00**
Plus: Trade Receivables sold	—	—	—	—	—
Plus: OLA rent	9.50	9.00	8.50	7.50	8.00
Less: Captive finance revenues	0.00	0.00	0.00	0.00	0.00
Plus: Captive finance operating expense	0.00	0.00	0.00	0.00	0.00
Plus: Revenues, consolidating (deconsolidating)	—	—	—	—	—
Less: Expenses, consolidating (deconsolidating)	0.00	0.00	0.00	0.00	0.00
Less: Nonrecourse interest	0.00	0.00	0.00	0.00	0.00
Less: Securitized interest	0.00	0.00	0.00	0.00	0.00
Less: Amortized portion of nonrecourse debt	0.00	0.00	0.00	0.00	0.00
Less: Amortized portion of securitized debt	0.00	0.00	0.00	0.00	0.00
Plus: ARO finance costs	4.00	3.00	3.00	0.00	2.00

Kentucky Utilities Co.	BBB/Watch Pos/A-2	USD In Millions	
Sub-sector: Utilities	Industry: Electric	[1]CDS: —	[1]CDS 90 day Hi/Lo: —	[1]CDS-MDS: —
Rev: 1,730.00	EBITDA: 662.14	Debt/EBITDA: 3.68x	EBITDA Int Cov: 7.21x

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Adjusted Income statement as of December 02, 2014

	Annual 31-Dec-2013 USD	Annual 31-Dec-2012 USD	Annual 31-Dec-2011 USD	Annual 31-Dec-2010 USD	Annual 31-Dec-2009 USD
Plus: PPA depreciation	—	—	—	—	—
Plus: PPA interest expense	0.00	0.00	0.00	0.00	0.00
Less: Capitalized development costs	0.00	0.00	0.00	0.00	0.00
Less: Infrastructure renewal costs	0.00	0.00	0.00	0.00	0.00
Plus: Capitalized interest (EBITDA transfer from inventory)	—	—	—	—	—
Plus: Exploration costs	—	—	—	—	—
Plus: Dividends received from equity investments	—	—	—	—	—
Plus: Pension & other postretirement expense	4.64	8.40	12.90	15.00	18.00
Plus: Stock compensation expense	—	—	—	—	—
Plus: Revenues - Finance/Interest Income	—	—	—	—	—
Plus: Revenues - Profit on disposals	—	—	—	—	—
Plus: Revenues - Derivatives	—	—	—	—	—
Plus: Revenues - Other	—	—	—	—	—
COGS- Restructuring costs	—	—	—	—	—
COGS- Valuation gains/(losses)	—	—	—	—	—
COGS- Other non-operating nonrecurring items	—	—	—	—	—
Plus: COGS- LIFO Liquidation gains	—	—	—	—	—
SG&A- Restructuring costs	—	—	—	—	—
SG&A- Valuation gains/(losses)	—	—	—	—	—
SG&A- Other non-operating nonrecurring items	—	—	—	—	—
R&D- Restructuring costs	—	—	—	—	—
R&D- Valuation gains/(losses)	—	—	—	—	—
R&D- Other non-operating nonrecurring items	—	—	—	—	—
RMS&M- Restructuring costs	—	—	—	—	—
RMS&M Valuation gains/(losses)	—	—	—	—	—
RMS&M- Other non-operating nonrecurring items	—	—	—	—	—
Staff - Restructuring costs	—	—	—	—	—
Staff - Valuation gains/(losses)	—	—	—	—	—
Staff - Other non-operating nonrecurring items	—	—	—	—	—

Kentucky Utilities Co.		BBB/Watch Pos/A-2	USD in Millions	
Sub-sector: Utilities	Industry: Electric	[1]CDS: —	[1]CDS 90 day Hi/Lo: —	[1]CDS-MDS: —
Rev: 1,730.00	EBITDA: 662.14	Debt/EBITDA: 3.68x	EBITDA Int Cov: 7.21x	

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Adjusted Income statement as of December 02, 2014

	Annual 31-Dec-2013 USD	Annual 31-Dec-2012 USD	Annual 31-Dec-2011 USD	Annual 31-Dec-2010 USD	Annual 31-Dec-2009 USD
Plus: EBITDA - Income (expense) of unconsolidated companies	—	—	—	—	—
Plus: EBITDA - Gain/(Loss) on disposals of PP&E	—	—	—	—	—
Plus: EBITDA - Foreign Exchange gain/(loss)	—	—	—	—	—
Plus: EBITDA - Restructuring costs	—	—	—	—	—
Plus: EBITDA - Derivatives	—	—	—	—	—
Plus: EBITDA - Settlement (litigation/insurance) costs	—	—	—	—	—
Plus: EBITDA - Valuation gains/(losses)	—	—	—	—	—
Plus: EBITDA - Business Divestments	—	—	—	—	—
Plus: EBITDA - Inventory	—	—	—	—	—
Plus: EBITDA - Other income/(expense)	—	—	—	—	—
EBITDA, adjusted	**637.14**	**530.40**	**563.40**	**517.50**	**430.00**
	—	—	—	—	—
Summary FFO Calculation	—	—	—	—	—
EBITDA, adjusted	637.14	530.40	563.40	517.50	430.00
Less: Interest expense, adjusted	80.09	82.90	84.52	91.43	91.47
Plus: Interest and dividend income, adjusted	0.00	0.00	0.00	0.00	0.00
Less: Current taxes, adjusted	70.29	(18.35)	6.74	72.08	(4.36)
Plus/minus: Other (exploration costs & FFO other)	0.00	0.00	0.00	0.00	0.00
FFO, adjusted	486.77	465.85	472.14	353.99	342.89
	—	—	—	—	—
Funds from operations	—	—	—	—	—
EBITDA, pre-adjusted	619.00	510.00	539.00	495.00	402.00
Less: Interest expense, pre-adjusted	(70.00)	(69.00)	(70.00)	(78.00)	(75.00)
Plus: Interest income, pre-adjusted	—	—	—	—	—
Less: Current tax expense, pre-adjusted	(63.00)	21.00	4.00	(71.00)	4.00
Less: Capitalized interest	0.00	0.00	0.00	0.00	0.00
Less: Capitalized interest within inventory	0.00	0.00	0.00	0.00	0.00
Plus: Capitalized interest (EBITDA transfer from inventory)	—	—	—	—	—
Plus: Trade Receivables sold	—	—	—	—	—

Kentucky Utilities Co. | BBB/Watch Pos/A-2 | USD in Millions

Sub-sector: Utilities | Industry: Electric | ¹CDS: — | ¹CDS 90 day Hi/Lo: — | ¹CDS-MDS: —

Rev: 1,730.00 | EBITDA: 662.14 | Debt/EBITDA: 3.68x | EBITDA Int Cov: 7.21x

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Adjusted Income statement as of December 02, 2014

	Annual 31-Dec-2013 USD	Annual 31-Dec-2012 USD	Annual 31-Dec-2011 USD	Annual 31-Dec-2010 USD	Annual 31-Dec-2009 USD
Less: Interest from receivables sold	0.00	0.00	0.00	0.00	0.00
Less: receivables sold interest adjustment	0.00	0.00	0.00	0.00	0.00
Plus: OLA rent	9.50	9.00	8.50	7.50	8.00
Less: OLA interest	(2.58)	(2.34)	(1.78)	(1.68)	(1.73)
Less: Captive finance revenues	0.00	0.00	0.00	0.00	0.00
Plus: Captive finance operating expense	0.00	0.00	0.00	0.00	0.00
Less: Captive finance investment income	0.00	0.00	0.00	0.00	0.00
Plus: Captive finance interest	0.00	0.00	0.00	0.00	0.00
Plus: Captive finance tax effect	0.00	0.00	0.00	0.00	0.00
Plus: Revenues, consolidating (deconsolidating)	—	—	—	—	—
Less: Expenses, consolidating (deconsolidating)	0.00	0.00	0.00	0.00	0.00
Less: Interest expense, consolidating (deconsolidating)	0.00	0.00	0.00	0.00	0.00
Less: Nonrecourse interest	0.00	0.00	0.00	0.00	0.00
Less: Securitized interest	0.00	0.00	0.00	0.00	0.00
Less: Amortized portion of nonrecourse debt	0.00	0.00	0.00	0.00	0.00
Less: Amortized portion of securitized debt	0.00	0.00	0.00	0.00	0.00
Plus: Nonrecourse interest	—	—	—	—	—
Plus: Securitized interest	—	—	—	—	—
Plus: ARO finance costs included in EBITDA	4.00	3.00	3.00	0.00	2.00
Less: Total ARO finance costs	(4.00)	(3.00)	(3.00)	0.00	(2.00)
Plus:Return on ARO plan assets	—	—	—	—	—
Less: tax effect on ARO net interest cost	1.40	(0.70)	1.40	0.00	0.70
Plus: PPA depreciation	—	—	—	—	—
Plus: PPA interest expense	0.00	0.00	0.00	0.00	0.00
Less: PPA interest expense	0.00	0.00	0.00	0.00	0.00
Less: Capitalized development costs	0.00	0.00	0.00	0.00	0.00
Less: Infrastructure renewal costs	0.00	0.00	0.00	0.00	0.00
Plus: Dividends received from equity investments	—	—	—	—	—
Plus: Pension & other postretirement expenses (EBITDA adjustment)	4.64	8.40	12.90	15.00	18.00

Kentucky Utilities Co.		BBB/Watch Pos/A-2	USD In Millions	
Sub-sector: Utilities	Industry: Electric	[1]CDS: —	[1]CDS 90 day Hi/Lo: —	[1]CDS-MDS: —
Rev: 1,730.00	EBITDA: 662.14	Debt/EBITDA: 3.68x	EBITDA Int Cov: 7.21x	

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Adjusted Income statement as of December 02, 2014

	Annual 31-Dec-2013 USD	Annual 31-Dec-2012 USD	Annual 31-Dec-2011 USD	Annual 31-Dec-2010 USD	Annual 31-Dec-2009 USD
Less: Pension & other postretirement interest expense	(1.68)	(6.74)	(7.91)	(9.92)	(11.03)
Less: Pension & other postretirement tax effect	(8.69)	(1.95)	(12.14)	(1.08)	(0.34)
Plus: Exploration costs	—	—	—	—	—
Less: Exploration costs	0.00	0.00	0.00	0.00	0.00
Plus: Stock compensation expense	—	—	—	—	—
Less: Low equity hybrid dividend accrual	0.00	0.00	0.00	0.00	0.00
Plus: High equity hybrid interest expense	—	—	—	—	—
Plus: Intermediate-equity hybrid interest expense	0.00	0.00	0.00	0.00	0.00
Less: Intermediate-equity hybrid dividend accrual	0.00	0.00	0.00	0.00	0.00
Plus: Revenues - Finance/Interest Income	—	—	—	—	—
Plus: Revenues - Profit on disposals	—	—	—	—	—
Plus: Revenues - Derivatives	—	—	—	—	—
Plus: Revenues - Other	—	—	—	—	—
Plus: COGS- Restructuring costs	—	—	—	—	—
Plus: COGS- Valuation gains/(losses)	—	—	—	—	—
Plus: COGS- Other non-operating nonrecurring items	—	—	—	—	—
Plus: COGS- LIFO Liquidation gains	—	—	—	—	—
Plus: SG& A- Restructuring costs	—	—	—	—	—
Plus: SG& A- Valuation gains/(losses)	—	—	—	—	—
Plus: SG& A- Other non-operating nonrecurring items	—	—	—	—	—
Plus: R& D- Restructuring costs	—	—	—	—	—
Plus: R& D- Valuation gains/(losses)	—	—	—	—	—
Plus: R& D- Other non-operating nonrecurring items	—	—	—	—	—
Plus: RMS& M- Restructuring costs	—	—	—	—	—
Plus: RMS& M Valuation gains/(losses)	—	—	—	—	—
Plus: RMS& M- Other non-	—	—	—	—	—

Kentucky Utilities Co.		BBB/Watch Pos/A-2	USD In Millions	
Sub-sector: Utilities	Industry: Electric	¹CDS: —	¹CDS 90 day Hi/Lo: —	¹CDS-MDS: —
Rev: 1,730.00	EBITDA: 662.14	Debt/EBITDA: 3.68x	EBITDA Int Cov: 7.21x	

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Adjusted Income statement as of December 02, 2014

	Annual 31-Dec-2013 USD	Annual 31-Dec-2012 USD	Annual 31-Dec-2011 USD	Annual 31-Dec-2010 USD	Annual 31-Dec-2009 USD
operating nonrecurring items					
Plus: Staff - Restructuring costs	—	—	—	—	—
Plus: Staff - Valuation gains/(losses)	—	—	—	—	—
Plus: Staff - Other non-operating nonrecurring items	—	—	—	—	—
Plus: EBITDA - Income (expense) of unconsolidated companies	—	—	—	—	—
Plus: EBITDA - Gain/(Loss) on disposals of PP& E	—	—	—	—	—
Plus: EBITDA - Fair value changes of contingent consideration	—	—	—	—	—
Plus: EBITDA - Foreign Exchange gain/(loss)	—	—	—	—	—
Plus: EBITDA - Restructuring costs	—	—	—	—	—
Plus: EBITDA - Derivatives	—	—	—	—	—
Plus: EBITDA - Streaming transactions	—	—	—	—	—
Plus: EBITDA - Settlement (litigation/insurance) costs	—	—	—	—	—
Plus: EBITDA - Valuation gains/(losses)	—	—	—	—	—
Plus: EBITDA - Business Divestments	—	—	—	—	—
Plus: EBITDA - Inventory	—	—	—	—	—
Plus: EBITDA - Other income/(expense)	—	—	—	—	—
Plus: EBITDA - Other	—	—	—	—	—
Less: Interest expense - Derivatives	0.00	0.00	0.00	0.00	0.00
Less: Interest expense - Shareholder loan	0.00	0.00	0.00	0.00	0.00
Less: Interest expense - Amortized cost	0.00	0.00	0.00	0.00	0.00
Less: Interest expense - Streaming transactions	0.00	0.00	0.00	0.00	0.00
Less: Interest expense - Other	(1.82)	(1.82)	(1.82)	(1.82)	(1.70)
FFO - other	—	—	—	—	—
FFO, adjusted	486.77	465.86	472.14	353.99	342.89

ⓓMedia Release:Ratings On Four Kentucky Utilities Co.-Related Joint-Supported Bond Issues Affirmed, published 01-Oct-2014

Header information displayed is for the most recent data available with S&P Adjusted LTM financials.

[1]CDS Data provided by CMA DataVision as of previous day closing values, EST.

STANDARD
&POOR'S

RATINGSDIRECT

September [illegible]

Kentucky Utilities Co.

Primary Credit Analyst:
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Outlook

The stable outlook on E.ON U.S. is based on continued support from E.ON AG and a corporate strategy that maintains a primarily low-risk, utility-based business risk profile. The ratings and outlook for E.ON U.S. and its subsidiaries are linked to those on E.ON AG. The importance of E.ON AG's U.S. operations to its group strategy remains a factor in the ratings on E.ON U.S. Any change in the parent's attitude toward its U.S. holdings or in Standard & Poor's Ratings Services' perception of the parent's support could lead to a rating change. Completion of the Big Rivers transaction would lessen the company's exposure to unregulated activities and could eventually lead to an improved business risk profile and higher ratings.

Accounting

The financial statements of E.ON U.S. are provided to Standard & Poor's, conform to U.S. GAAP, and PricewaterhouseCoopers LLC audits them. The separate financial statements of the company's interests in three Argentine gas utilities are not part of that audit, but do not represent a material part of either the overall financial picture of the company or its credit profile. With U.S. business activity consisting mainly of electric utility operations, most of the financials are subject to regulatory accounting under SFAS No. 71. The incentive to undertake any sustained effort to accelerate revenues or defer expenses to boost earnings is reduced with cost-of-service regulated businesses, as doing so would mainly serve to justify lower rates.

Table 1

Kentucky Utilities Co. -- Financial Summary*

Industry Sector: Electric

	--Fiscal year ended Dec. 31--				
	2007	**2006**	**2005**	**2004**	**2003**
Rating history	BBB+/Stable/A-2	BBB+/Stable/A-2	BBB+/Stable/A-2	BBB+/Stable/A-2	BBB+/Stable/A-2
(Mil. $)					
Revenues	1,273.0	1,210.0	1,206.6	995.4	891.8
Net income from continuing operations	167.0	152.0	112.1	133.5	91.4
Funds from operations (FFO)	323.9	249.6	234.4	213.3	238.8
Capital expenditures	745.3	349.5	140.0	156.4	341.9
Cash and short-term investments	0	6.0	6.7	4.6	4.9
Debt	1,465.5	1,146.9	1,061.8	976.1	956.0
Preferred stock	0	0	0	39.7	40.0
Equity	1,435.0	1,193.0	974.9	965.0	906.7
Debt and equity	2,900.5	2,339.9	2,036.7	1,941.0	1,864.6
Adjusted ratios					
EBIT interest coverage (x)	4.9	6.1	5.8	7.8	5.0
FFO int. cov. (x)	5.8	6.3	7.0	7.8	7.2
FFO/debt (%)	22.1	21.8	22.1	21.9	24.9
Discretionary cash flow/debt (%)	(29.5)	(11.0)	2.7	(1.1)	(10.8)
Net Cash Flow / Capex (%)	43.5	71.4	130.4	94.6	69.2
Debt/debt and equity (%)	50.5	49.0	52.1	50.3	51.4

Ratings Detail (As Of September 26, 2003)* (cont.)

Corporate Credit Ratings History	
04-Aug-2003	BBB+/Stable/A-2
12-Sep-2002	A-/Stable/A-2
09-Apr-2001	BBB+/Watch Pos/A-2
Financial Risk Profile	Intermediate
Related Entities	
Central Networks East PLC	
Issuer Credit Rating	A/Stable/A-1
E.ON AG	
Issuer Credit Rating	A/Stable/A-1
Commercial Paper	A-1
Senior Unsecured (27 Issues)	A
Short-Term Debt (1 Issue)	A-1
E.ON Energy Ltd.	
Issuer Credit Rating	A/Stable/A-1
E.ON U.K. PLC	
Issuer Credit Rating	A/Stable/A-1
Senior Unsecured (2 Issues)	A
E.ON U.S. LLC	
Issuer Credit Rating	BBB+/Stable/--
Louisville Gas & Electric Co.	
Issuer Credit Rating	BBB+/Stable/NR
Senior Secured (3 Issues)	AA/Negative
Senior Secured (1 Issue)	BBB+
Senior Secured (7 Issues)	BBB+/A-2
Senior Unsecured (4 Issues)	AA/Negative
Powergen (East Midlands) Investments	
Issuer Credit Rating	A/Stable/--

*Unless otherwise noted, all ratings in this report are global scale ratings. Standard & Poor's credit ratings on the global scale are comparable across countries. Standard & Poor's credit ratings on a national scale are relative to obligors or obligations within that specific country.

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RESEARCH

Kentucky Utilities Co.

Publication date: 19-Jun-2006
Primary Credit Analyst: Todd A Shipman, CFA, New York (1) 212-438-7676; todd_shipman@standardandpoors.com

Corporate Credit Rating

BBB+/Stable/A-2

Financial risk profile:
Intermediate
Debt maturities:
(for LG&E Energy LLC)
2006 $186 mil.
2007 $61 mil.
2008 $150 mil.
2009 None

Outstanding Rating(s)	
Kentucky Utilities Co.	
Sr secd debt	
Local currency	A
CP	
Local currency	A-2
Pfd stk	
Local currency	BBB-
E.ON AG	
Corporate Credit Rating	AA-/Watch Neg/A-1+
Sr unsecd debt	AA-/Watch Neg
CP	
Local currency	/Watch NegA-1+
CP	
Foreign currency	NR
Powergen Ltd.	
Corporate Credit Rating	A-/Stable/A-2
Sr unsecd debt	
Foreign currency	BBB+
E.ON U.K. PLC	
Corporate Credit Rating	A-/Stable/A-2
Sr unsecd debt	A-
E.ON U.S. LLC	
Corporate Credit Rating	BBB+/Stable/--
Central Networks East PLC	
Corporate Credit Rating	A-/Stable/A-2
E.ON U.S. Capital Corp	
Corporate Credit Rating	BBB+/Stable/NR
Sr unsecd debt	
Local currency	BBB
Louisville Gas & Electric Co.	
Corporate Credit Rating	BBB+/Stable/NR
Sr secd debt	
Local currency	A-
Pfd stk	
Local currency	BBB-

Powergen (East Midlands) Investments	
Corporate Credit Rating	A-/Stable/--
Sr unsecd debt	A-
Powergen Retail Ltd.	
Corporate Credit Rating	A-/Stable/A-2

Corporate Credit Rating History	
Sept. 12, 2002	A-/A-2
Aug. 4, 2003	BBB+/A-2

Major Rating Factors

Strengths:

- Implicit credit support provided by ultimate parent E.ON AG, and
- Stable electric utility operations (and associated cash flow) that benefit from a supportive regulatory environment.

Weaknesses:

- Dependence on overseas parent for capital infusions and liquidity;
- Environmental compliance, pension obligations, and capital expenditures require capital infusions; and
- The residue of ill-timed, non-utility investments that produce negative cash flow.

Rationale

The ratings on Kentucky Utilities Co. are based on the credit profile of parent E.ON U.S. LLC. The E.ON U.S. ratings reflect the credit characteristics of the two operating utilities in Kentucky--Kentucky Utilities and Louisville Gas & Electric Co.--and the company's focus on operating the fully integrated utilities, with implicit support for credit quality from E.ON U.S.'s ultimate parent, E.ON AG (AA-/Watch Neg/A-1+), factored into the analysis. E.ON has prominently expressed its support for E.ON U.S. and its intent to maintain its U.S. presence.

The company's business risk profile is rated '6' (satisfactory), and its financial risk profile is considered intermediate. (Utility business risk profiles are categorized from '1' (excellent) to '10' (vulnerable).)

The company's satisfactory business risk profile is supported by low-risk, regulated, and financially sound gas distribution and electric operations; efficient generation facilities that allow for competitive rates; and a supportive regulatory environment. The company's electric operations benefit from a fuel adjustment mechanism and an environmental cost recovery mechanism, while the company's smaller gas operations benefit from a weather normalization adjustment clause and a cost-of-gas cost adjustment mechanism. Together, these mechanisms reduce exposure to environmental requirements, weather, and potential volatility in natural gas prices, all of which normally raise credit-related concerns. Some regulatory uncertainty is apparent in the Attorney General's challenge of the 2004 rate decisions for the E.ON U.S. utilities. Standard & Poor's Ratings Services does not expect, and current ratings do not reflect, any disruption in the current rates for the utilities.

Unregulated operations, a large industrial customer base, and coal-fired generation facilities that require large environmental expenditures detract from the business risk profile. E.ON U.S. may significantly reduce its unregulated operations if a preliminary agreement to exit its involvement with Big Rivers Electric Corp. is finalized. Currently, E.ON U.S. leases and operates four of Big River's power plants.

Table 1

E.ON U.S. LLC Major Utility Subsidiaries Comparison

	--Fiscal year ended Dec. 31, 2004--								
Company name	Fuel	Variable prod	Prod NF	Purch pwr	Tot prod	Tot pwr supp	Residential rates	Commercial rates	Industrial rates
($/MWh)									

AEP Generating Co.	13.21	13.62	18.13	N.A.	31.34	31.35	N.A.	N.A.	[illegible]
Appalachian Power Co.	13.93	15.20	17.29	20.94	31.22	27.62	53.77	48.80	34.7[illegible]
Cincinnati Gas & Electric Co.	15.28	17.88	28.94	630.02	44.22	227.02	76.31	67.61	44.56
Cleveland Electric Illuminating Co.	6.51	8.49	26.36	37.62	32.87	35.37	101.96	100.12	59.92
Columbus Southern Power Co.	14.45	16.12	26.37	25.90	40.82	33.68	75.78	62.79	48.46
Consumers Energy Co.	N.A.	N.A.	7.91	N.A.	7.91	5.34	80.73	76.39	54.15
Dayton Power & Light Co.	15.00	17.79	39.31	38.50	54.31	52.43	87.43	69.82	58.15
Detroit Edison Co.	13.23	14.91	32.87	37.06	46.10	47.11	85.52	79.12	44.84
Duquesne Light Co.	N.A.	N.A.	N.A.	39.12	0.00	25.87	94.86	71.75	48.21
Indiana Michigan Power Co.	8.94	10.90	22.97	22.30	31.91	29.24	66.44	59.16	42.25
Indiana-Kentucky Electric Corp.	13.51	14.52	13.49	N.A.	27.00	27.00	N.A.	N.A.	N.A.
Indianapolis Power & Light Co.	11.47	12.45	21.20	54.24	32.67	33.06	63.00	68.16	46.15
Kentucky Power Co.	15.18	16.38	15.23	24.26	30.41	27.85	53.49	55.33	34.51
Kentucky Utilities Co.	17.08	18.02	18.13	18.12	35.21	29.83	49.29	47.14	36.25
Kingsport Power Co.	N.A.	N.A.	N.A.	29.80	N.A.	29.80	48.64	51.75	32.58
Louisville Gas & Electric Co.	12.77	13.78	22.35	22.54	35.12	32.65	61.36	55.28	39.67
Monongahela Power Co.	12.28	13.62	22.62	44.22	34.90	39.28	71.80	58.41	37.54
Northern Indiana Public Service Co.	14.94	16.13	28.44	39.72	43.38	42.87	95.07	81.70	44.48
Ohio Edison Co.	3.97	6.33	29.95	33.84	33.92	33.86	98.43	97.40	54.63
Ohio Power Co.	12.38	13.77	16.35	19.76	28.73	27.85	66.26	56.86	36.17
Ohio Valley Electric Corp.	14.16	15.16	11.86	22.66	26.02	24.24	N.A.	N.A.	36.87
Pennsylvania Power Co.	3.89	6.70	19.34	33.78	23.23	28.26	89.64	77.98	52.53
Potomac Edison Co.	N.A.	N.A.	27.74	37.80	27.74	36.14	68.20	61.29	37.50
PSI Energy Inc.	14.06	16.53	22.32	29.20	36.38	35.35	70.12	65.23	38.77
Southern Indiana Gas & Electric Co.	14.78	16.27	25.35	5.88	40.13	28.39	81.37	64.04	43.79
Toledo Edison Co.	6.40	8.52	37.82	33.88	44.22	38.85	101.82	101.19	41.74
Union Light, Heat & Power Co.	N.A.	N.A.	N.A.	38.52	N.A.	38.52	65.79	58.03	50.50
West Penn Power Co.	N.A.	N.A.	N.A.	33.56	N.A.	33.63	67.87	58.23	44.26
Wheeling Power Co.	N.A.	N.A.	N.A.	27.94	N.A.	27.94	60.49	55.09	33.84
ECAR avg.	12.16	13.78	23.01	53.89	32.79	38.98	74.40	66.86	43.67
Standard & Poor's avg.	23.42	24.53	49.65	60.01	71.28	51.89	98.65	88.74	66.03

MWh--Megawatt-hour. N.A.--Not applicable or available.

Table 2

Kentucky Utilities Co. Financial Summary

	--Fiscal year ended Dec. 31--				
	2005	2004	2003	2002	2001
Rating history	BBB+/Stable/A-2	BBB+/Stable/A-2	BBB+/Stable/A-2	A-/Stable/A-2	BBB+/Watch Pos/A-2
(Mil. $)					
Total revenues	1,206.6	995.4	891.0	888.2	859.5
Net income continuing	112.1	133.5	91.4	93.4	96.3
Funds from operations (FFO)	242.0	212.1	242.6	174.9	213.2
Capital expenditures	140.0	156.4	341.9	237.9	142.4
Cash and investments	6.7	4.6	4.9	5.4	3.3
Total debt	1,044.3	976.1	958.0	841.6	726.5
Preferred stock	0.0	39.7	40.0	40.0	40.0
Common equity	974.9	925.2	866.7	771.8	731.7
Total capital	2,019.2	1,941.0	1,864.6	1,653.4	1,498.2

Adjusted ratios

EBIT interest coverage (x)	5.9	7.8	5.0	5.3	4.6
FFO int. cov. (x)	7.4	7.8	7.3	6.4	8.0
FFO/total debt (%)	23.2	21.7	25.3	20.8	29.3
Discretionary cash flow/total debt (%)	2.8	(1.054)	(10.845)	(8.178)	1.3
Net cash flow/capital expenditure (%)	135.9	93.9	70.3	72.6	126.7
Total debt/total capital (%)	51.7	50.3	51.4	50.9	46.5
Return on average equity (%)	11.1	14.1	10.4	11.8	13.4
Common dividend payout ratio (unadj.) (%)	45.3	46.9	0.0	0.0	32.4

Note: Figures are fully adjusted, including postretirement obligations.

Table 3

Kentucky Utilities Co. Market Segments

	2004	2003	2002	2001
Sales				
Total retail (GWh)	18,212	17,594	17,633	16,636
Residential (%)	33.8	34.1	35.1	34.1
Commercial (%)	23.7	23.9	23.6	24.0
Industrial (%)	33.7	33.1	32.6	33.0
Other (%)	8.8	8.8	8.7	8.9
Wholesale (GWh)	5,707	5,591	5,780	7,713
Total sales (GWh)	23,919	23,185	23,413	24,349
Revenue				
Total retail (mil. $)	805	739	708	643
Residential (%)	37.7	37.7	38.8	37.9
Commercial (%)	25.7	25.6	25.2	25.7
Industrial (%)	27.6	27.8	27.1	27.2
Other (%)	8.0	8.0	7.9	8.1
Wholesale (mil. $)	160	138	144	203
Total revenue (mil. $)	965	877	852	846
Annual sales growth (%)				
Residential	2.7	(3.178)	9.2	(0.636)
Commercial	2.7	1.2	4.3	0.9
Industrial	5.1	1.8	4.6	(5.549)
Total retail	3.5	(0.224)	6.0	(1.987)
Wholesale	2.1	(3.273)	(25.067)	1.0
Total sales growth	3.2	(0.977)	(3.843)	(0.805)
Retail customer growth	1.4	1.0	1.4	1.3

GWh--Gigawatt-hour.

rating, it receives no payment for doing so, except for subscriptions to its publications. Additional information about our rating fees is available at www.standardandpoors.com/usratingsfees.

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May 4, 2005

Kentucky Utilities Co.

Primary Credit Analyst:

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Kentucky Utilities Co.

Corporate Credit Rating

BBB+/Stable/A-2

Business Profile

1 2 3 4 $\boxed{5}$ 6 7 8 9 10

Financial Policy:

Moderate

Debt maturities:

(for LG&E Energy LLC)
2005: $76 million
2006: $186 million
2007: $61 million
2008: $150 million

Outstanding Rating(s)

Kentucky Utilities Co.	
Sr secd debt	
Local currency	A
CP	
Local currency	A-2
Pfd stk	
Local currency	BBB-
E.ON AG	
Corporate Credit Rating	AA-/Negative/A-1+
Sr unsecd debt	AA-
CP	
Local currency	A-1+
CP	
Foreign currency	NR
E.ON International Finance B.V.	
Sr unsecd debt	NR
Powergen Ltd.	
Corporate Credit Rating	A-/Stable/A-2
Sr unsecd debt	
Foreign currency	BBB+
E.ON U.K. PLC	
Corporate Credit Rating	A-/Stable/A-2
Sr unsecd debt	A-
LG&E Energy LLC	
Corporate Credit Rating	BBB+/Stable/--
Powergen U.S. Holdings Ltd.	

Corporate Credit Rating	A-/Stable/A-2
Sr unsecd debt	
Foreign currency	BBB+
Central Networks East PLC	
Corporate Credit Rating	A-/Stable/A-2
LG&E Capital Corp.	
Corporate Credit Rating	BBB+/Stable/NR
Sr unsecd debt	
Local currency	BBB
Louisville Gas & Electric Co.	
Corporate Credit Rating	BBB+/Stable/NR
Sr secd debt	
Local currency	A-
Pfd stk	
Local currency	BBB-
Powergen (East Midlands) Investments	
Corporate Credit Rating	A-/Stable/--
Sr unsecd debt	A-
Powergen Retail Ltd.	
Corporate Credit Rating	A-/Stable/A-2
Corporate Credit Rating History	
Dec. 6, 2000	BBB+/A-2
Sept. 12, 2002	A-/A-2
Aug. 4, 2003	BBB+/A-2

Major Rating Factors

Strengths:

- Implicit credit support provided by ultimate parent E.ON AG; and
- Stable electric utility operations (and associated cash flow) that benefit from supportive regulatory environment.

Weaknesses:

- Dependent on overseas parent for capital infusions and liquidity;
- Environmental compliance, pension obligations, and capital expenditures require capital infusions; and
- Ill-timed, nonregulated investments at the parent that collectively contribute negative cash flow.

Rationale

The ratings on Kentucky Utilities Co. (KU) are tied to the consolidated credit profile of immediate parent LG&E Energy LLC (LG&E; BBB+/Stable/--), which is based primarily on the business activities of its two operating utilities in Kentucky and the company's strategic focus on operating the fully integrated utilities. Implicit support for credit quality from LG&E's ultimate parent, E.ON AG (AA-/Stable/A-1+), is factored into the analysis. LG&E's own credit profile has improved to bring it closer to the 'BBB+' rating. However, the degree of E.ON support attributed by Standard & Poor's has not moved beyond that level. The net effect on ratings is neutral.

LG&E's average business profile is supported by low-risk, regulated, and financially sound gas distribution and electric operations, efficient generation facilities that allow for competitive rates, and a supportive regulatory environment. The company's electric operations benefit from a cost-of-fuel-adjustment mechanism and an environmental cost-recovery mechanism, while the company's smaller gas operations benefit from a weather normalization-adjustment clause and a cost-of-gas-adjustment mechanism. Together, these mechanisms reduce exposure to environmental legislation, weather, and potential volatility in natural gas prices, all of which normally concern Standard & Poor's.

The support from E.ON previously incorporated in the credit analysis was based on the expectation that LG&E played an important, long-term role in E.ON's worldwide strategy. However, Standard & Poor's believes E.ON does not intend to affirmatively pursue expansion of its U.S. presence. The company's financial picture is now more consistent with its current rating due to the roughly $1 billion of acquisition debt at an intermediate holding company that matured in October 2004.

Liquidity

During the short term, Standard & Poor's expects consolidated capital expenditures to exceed cash flow from operations due to significant environmental expenditures and contributions for the company's underfunded pension and other postretirement benefit obligations. The steady internal cash flow generated by LG&E's regulated operations will not be enough to meet these obligations, thus creating a reliance on external financing. Such funding is expected to be concentrated at E.ON, which is also expected to provide support in the case of short-term liquidity needs. (A cross-default clause in E.ON's credit facility protects LG&E as long as it is a "material subsidiary".)

LG&E's adequate liquidity is augmented by E.ON. An E.ON-related entity provides a $150 million credit facility to LG&E to ensure funding availability for its money pool (about $80 million was outstanding under this facility as of third-quarter 2004).

Some other favorable points include:

- Rate relief at LG&E's regulated entities should favorably affect cash flow, and
- Consolidated debt maturities through 2008 are a manageable 22% of LG&E's total debt.

Some unfavorable points include:

- LG&E has limited room for capital-expenditure reductions, as projected generation outlays are required to maintain reserve margins. Projected growth expenditures will require external funding, and
- Although the company operates various diversified businesses, Standard & Poor's believes any sales would generate little net cash.

Outlook

The stable outlook is based on continued support from E.ON and a corporate strategy that maintains a primarily low-risk, utility-based business profile. Unregulated operations (including asset-based energy marketing that exposes the company to weakening power prices in its off-system sales program), a large industrial customer base, and coal-fired generation facilities that require large environmental expenditures detract from LG&E's business profile. A change in either the ratings or the outlook on LG&E and its subsidiaries is unlikely, absent a change in how the company fits into E.ON's corporate strategy.

Accounting

The financial statements of LG&E are provided to Standard & Poor's, conform to U.S. GAAP, and are audited by PricewaterhouseCoopers LLC. The separate financial statements of the company's interests in three Argentine gas utilities are not part of that audit, but do not represent a material part of either the overall financial picture of LG&E or its credit profile. With U.S. business activity comprising mainly electric utility operations, most of the financials are subject to regulatory accounting under SFAS No. 71. The incentive to undertake any sustained effort to accelerate revenues or defer expenses to boost earnings is reduced with cost-of-service regulated businesses, as it would mainly serve to justify lower rates in the future. LG&E carries a small amount of regulatory assets on its balance sheet. However, goodwill constitutes a significant proportion (40%) of the total assets of the company as a result of E.ON's purchase of LG&E.

Table 1

Kentucky Utilities Co. -- Financial Summary

	--Fiscal year ended Dec. 31--				
Rating history	BBB+/Stable/A-2	A-/Stable/A-2	BBB+/Watch Pos/A-2	BBB+/Negative/A-2	A+/Stable/A-1
	2003	**2002**	**2001**	**2000**	**1999**
(Mil. $)					
Sales	891.8	888.2	859.5	851.9	937.3
Net income from cont. oper.	91.4	93.4	96.3	95.5	106.6
Funds from oper. (FFO)	235.5	194.9	215.6	210.8	199.3
Capital expenditures	341.9	237.9	142.4	100.6	181.3
Cash and equivalents	4.9	5.4	3.3	0.3	6.8
Total debt	730.8	620.0	536.3	546.1	546.3
Preferred stock	40.0	40.0	40.0	40.0	40.0
Common equity	907.7	814.1	736.0	669.8	637.0
Total capital	1,678.5	1,474.1	1,311.3	1,255.9	1,223.3
Ratios					
Adj. EBIT interest coverage (x)	4.8	4.9	4.5	4.0	4.5
Adj. FFO interest coverage (x)	7.2	6.6	6.0	5.3	5.2
Adj. FFO/avg. total debt (%)	29.6	27.9	33.4	33.5	31.6
Net cash flow/capital expenditures (%)	68.2	81.0	128.3	113.4	68.5
Adj. total debt/capital (%)	47.5	46.2	46.1	47.0	48.1
Return on common equity (%)	10.4	11.8	13.4	14.3	16.8
Common dividend payout (%)	0.0	0.0	32.4	101.3	69.9

Table 2

Kentucky Utilities Co. -- Market Segments

	2003	**2002**	**2001**	**2000**	**1999**
Sales					
Total retail (GWh)	17,594	17,633	16,636	16,974	16,308
Residential (%)	34.1	35.1	34.1	33.7	33.4
Commercial (%)	23.9	23.6	24.0	23.3	23.1

Table 2

Kentucky Utilities Co. -- Market Segments (cont.)					
Industrial (%)	33.1	32.6	33.0	34.2	34.7
Other (%)	8.8	8.7	8.9	8.8	8.8
Wholesale (GWh)	5,591.0	5,780.2	7,713.0	7,573.1	10,188.3
Total Sales (GWh)	23,184.6	2,3413.3	24,349.1	24,546.6	26,495.9
Revenue					
Total retail (mil. $)	739.0	708.0	643.0	619.0	639.0
Residential (%)	37.7	38.8	37.9	37.8	37.6
Commercial (%)	25.6	25.2	25.7	25.2	25.0
Industrial (%)	27.8	27.1	27.2	28.0	28.4
Other (%)	8.0	7.9	8.1	8.0	8.1
Wholesale (mil. $)	138.0	144.0	203.0	198.0	287.0
Total revenue (mil. $)	877.0	852.0	846.0	817.0	926.0
Annual sales growth (%)					
Residential	(3.2)	9.2	(0.6)	4.9	3.8
Commercial	1.2	4.3	0.9	5.1	3.2
Industrial	1.6	4.6	(5.5)	2.6	1.4
Total retail	(0.2)	6.0	(2.0)	4.1	2.6
Standard & Poor's retail average	18.3	35.3	23.0	19.0	19.2
Wholesale	(3.3)	(25.1)	1.8	(25.7)	41.0
Total sales growth	(1.0)	(3.8)	(0.8)	(7.4)	14.6
Retail customer growth	1.0	1.4	1.3	1.8	1.8

GWh -- Gigawatt-hour.

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March 21, 2005

Kentucky Utilities Co.

Primary Credit Analyst:
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Major Rating Factors

Rationale

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Accounting

Kentucky Utilities Co.

Corporate Credit Rating

BBB+/Stable/A-2

Business Profile

1 2 3 4 $\boxed{5}$ 6 7 8 9 10

Financial Policy:

Moderate

Debt maturities:

(for LG&E Energy LLC)
2005 $76 million
2006 $186 million
2007 $61 million
2008 $150 million

Outstanding Rating(s)

Kentucky Utilities Co.	
Sr secd debt	
Local currency	A
CP	
Local currency	A-2
Pfd stk	
Local currency	BBB-
E.ON AG	
Corporate Credit Rating	AA-/Negative/A-1+
Sr unsecd debt	AA-
CP	
Local currency	A-1+
CP	
Foreign currency	NR
E.ON International Finance B.V.	
Sr unsecd debt	NR
Powergen Ltd.	
Corporate Credit Rating	A-/Stable/A-2
Sr unsecd debt	
Foreign currency	BBB+
E.ON U.K. PLC	
Corporate Credit Rating	A-/Stable/A-2
Sr unsecd debt	A-
LG&E Energy LLC	
Corporate Credit Rating	BBB+/Stable/--
Powergen U.S. Holdings Ltd.	

Corporate Credit Rating	A-/Stable/A-2
Sr unsecd debt	
Foreign currency	BBB+
Central Networks East PLC	
Corporate Credit Rating	A-/Stable/A-2
LG&E Capital Corp.	
Corporate Credit Rating	BBB+/Stable/NR
Sr unsecd debt	
Local currency	BBB
Louisville Gas & Electric Co.	
Corporate Credit Rating	BBB+/Stable/NR
Sr secd debt	
Local currency	A-
Pfd stk	
Local currency	BBB-
Powergen (East Midlands) Investments	
Corporate Credit Rating	A-/Stable/--
Sr unsecd debt	A-
Powergen Retail Ltd.	
Corporate Credit Rating	A-/Stable/A-2

Corporate Credit Rating History	
Dec. 6, 2000	BBB+/A-2
Sept. 12, 2002	A-/A-2
Aug. 4, 2003	BBB+/A-2

Major Rating Factors

Strengths:

- Implicit credit support provided by ultimate parent E.ON AG; and
- Stable electric utility operations (and associated cash flow) that benefit from supportive regulatory environment.

Weaknesses:

- Dependent on overseas parent for capital infusions and liquidity;
- Environmental compliance, pension obligations, and capital expenditures require capital infusions; and
- Ill-timed, nonregulated investments at the parent that collectively contribute negative cash flow.

Rationale

The 'BBB+' ratings on Kentucky Utilities Co. (KU) are tied to the consolidated credit profile of immediate parent LG&E Energy LLC (LG&E; BBB+/Stable/--), which is based primarily on the business activities of its two operating utilities in Kentucky and the company's strategic focus on operating the fully integrated utilities. Implicit support for credit quality from LG&E's ultimate parent, E.ON AG (AA-/Stable/A-1+), is factored into the analysis. LG&E's own credit profile has improved to bring it closer to the 'BBB+' rating. However, the degree of E.ON support attributed by Standard & Poor's has not moved beyond that level. The net effect on ratings is neutral.

LG&E's average business profile is supported by low-risk, regulated, and financially sound gas distribution and electric operations, efficient generation facilities that allow for competitive rates, and a supportive regulatory environment. The company's electric operations benefit from a cost-of-fuel-adjustment mechanism and an environmental cost-recovery mechanism, while the company's smaller gas operations benefit from a weather normalization-adjustment clause and a cost-of-gas-adjustment mechanism. Together, these mechanisms reduce exposure to environmental legislation, weather, and potential volatility in natural gas prices, all of which normally concern Standard & Poor's.

The support from E.ON previously incorporated in the credit analysis was based on the expectation that LG&E played an important, long-term role in E.ON's worldwide strategy. However, E.ON currently appears not to envision any expansion of its U.S. presence. The company's financial picture is now more consistent with its current rating due to the roughly $1 billion of acquisition debt at an intermediate holding company that matured in October 2004.

Liquidity

During the short term, Standard & Poor's expects consolidated capital expenditures to exceed cash flow from operations due to significant environmental expenditures, gas turbine construction costs, and contributions for the company's underfunded pension and other postretirement benefit obligations. The steady internal cash flow generated by LG&E's regulated operations will not be enough to meet these obligations, thus creating a reliance on external financing. Such funding is expected to be concentrated at E.ON, which is also expected to provide support in the case of short-term liquidity needs. (A cross-default clause in E.ON's credit facility protects LG&E as long as it is a "material subsidiary".)

LG&E's adequate liquidity is augmented by E.ON. An E.ON-related entity provides a $150 million credit facility to LG&E to ensure funding availability for its money pool (about $80 million was outstanding under this facility as of third-quarter 2004).

Some other favorable points include:

- Rate relief at LG&E's regulated entities should favorably affect cash flow, and
- Consolidated debt maturities through 2008 are a manageable 22% of LG&E's total debt.

Some unfavorable points include:

- LG&E has limited room for capital-expenditure reductions, as projected generation outlays are required to maintain reserve margins. Projected growth expenditures will require external funding, and
- Although the company operates various diversified businesses, Standard & Poor's believes any sales would generate little net cash.

Outlook

The stable outlook is based on continued support from E.ON and a corporate strategy that maintains a primarily low-risk, utility-based business profile. Unregulated operations (including asset-based energy marketing that expose the company to weakening power prices in its off-system sales program), a large industrial customer base, and coal-fired generation facilities that require large environmental expenditures detract from LG&E's business profile. A change in either ratings or the outlook on LG&E and its subsidiaries is unlikely, absent a change in how the company fits into E.ON's corporate strategy.

Accounting

The financial statements of LG&E are provided to Standard & Poor's, conform to U.S. GAAP, and are audited by PricewaterhouseCoopers LLC. The separate financial statements of the company's interests in three Argentine gas utilities are not part of that audit, but do not represent a material part of either the overall financial picture of LG&E or its credit profile. With U.S. business activity comprising mainly electric utility operations, most of the financials are subject to regulatory accounting under SFAS No. 71. The incentive to undertake any sustained effort to accelerate revenues or defer expenses to boost earnings is reduced with cost-of-service regulated businesses, as it would mainly serve to justify lower rates in the future. LG&E carries a small amount of regulatory assets on its balance sheet. However, goodwill constitutes a significant proportion (40%) of the total assets of the company as a result of E.ON's purchase of LG&E.

Table 1

Kentucky Utilities Co. -- Financial Summary

		--Fiscal year ended Dec. 31--				
Rating history	Avg. of past three fiscal years	BBB+/Stable/A-2	A-/Stable/A-2	BBB+/Watch Pos/A-2	BBB+/Negative/A-2	A+/Stable/A-1
		2003	2002	2001	2000	1999
(Mil. $)						
Sales	879.8	891.8	888.2	859.5	851.9	937.3
Net income from cont. oper.	93.7	91.4	93.4	96.3	95.5	106.6
Funds from oper. (FFO)	215.3	235.5	194.9	215.6	210.8	199.3
Capital expenditures	240.7	341.9	237.9	142.4	100.6	181.3
Cash and equivalents	4.5	4.9	5.4	3.3	0.3	6.8
Total debt	629.0	730.8	620.0	536.3	546.1	546.3
Preferred stock	40.0	40.0	40.0	40.0	40.0	40.0
Common equity	818.9	907.7	814.1	735.0	669.8	637.0
Total capital	1,488.0	1,678.5	1,474.1	1,311.3	1,255.9	1,223.3
Ratios						
Adj. EBIT interest coverage (x)	5.6	6.7	6.6	4.5	4.0	4.5
Adj. FFO interest coverage (x)	7.9	10.3	9.1	6.0	5.3	5.2
Adj. FFO/avg. total debt (%)	32.9	34.9	30.4	33.4	33.5	31.6
Net cash flow/capital expenditures (%)	84.3	68.2	81.0	128.3	113.4	68.5
Adj. total debt/capital (%)	43.9	43.5	42.1	46.1	47.0	48.1
Return on common equity (%)	11.7	10.4	11.8	13.4	14.3	16.8
Common dividend payout (%)	11.1	0.0	0.0	32.4	101.3	69.9

Table 2

Kentucky Utilities Co. -- Market Segments

	2003	2002	2001	2000	1999
Sales					
Total retail (GWh)	17,594	17,633	16,636	16,974	16,308
Residential (%)	34.1	35.1	34.1	33.7	33.4
Commercial (%)	23.9	23.6	24.0	23.3	23.1
Industrial (%)	33.1	32.6	33.0	34.2	34.7
Other (%)	8.8	8.7	8.9	8.8	8.8
Wholesale (GWh)	5,591	5,780	7,713	7,573	10,188
Total Sales (GWh)	23,185	23,413	24,349	24,547	26,496
Revenue					
Total retail (mil. $)	739	708	643	619	639
Residential (%)	37.7	38.8	37.9	37.8	37.6
Commercial (%)	25.6	26.2	25.7	25.2	25.0
Industrial (%)	27.8	27.1	27.2	28.0	28.4
Other (%)	8.0	7.9	8.1	8.0	8.1
Wholesale (mil. $)	138	144	203	198	287
Total revenue (mil. $)	877	852	846	817	926
Annual sales growth(%)					
Residential	(3.2)	9.2	(0.6)	4.9	3.8
Commercial	1.2	4.3	0.9	5.1	3.2
Industrial	1.6	4.6	(5.5)	2.6	1.4
Total retail	(0.2)	6.0	(2.0)	4.1	2.6
Standard & Poor's retail average	18.3	35.3	23.0	19.0	19.2
Wholesale	(3.3)	(25.1)	1.8	(25.7)	41.0
Total sales growth	(1.0)	(3.8)	(0.8)	(7.4)	14.6
Retail customer growth	1.0	1.4	1.3	1.8	1.8

GWh -- Gigawatt-hour.

Table 3

Kentucky Utilities Co. -- Costs and Rates 2003 Peer Analysis

$ per MWh

Company	Fuel	Variable Product	Prod NF	Purchased Power	Total Product	Total Power Supply	Residential Rates	Commercial Rates	Industrial Rates
AEP Generating Co.	12.16	12.5	9.3	0	21.46	21.47	N.A.	N.A.	N.A.
Appalachian Power Co.	13.25	14.05	3.05	22.04	16.3	18.83	54.3	48.51	35.56
Cincinnati Gas & Electric Co.	13.22	15.84	5.79	506.67	19.02	149.56	72.92	53.58	34.37
Cleveland Electric Illuminating Co.	6.83	12.66	29.11	37.34	35.94	36.82	73.4	84.95	59.42
Columbus Southern Power Co.	13.35	14.77	5.13	25.34	18.49	22.06	75.71	61.01	48.27
Detroit Edison Co.	13.12	14.65	7.57	41.73	20.69	24.01	86.21	78.03	49.14

Table 3

Kentucky Utilities Co. -- Costs and Rates 2003 Peer Analysis (cont.)									
Duquesne Light Co.	N.A.	N.A.	N.A.	38.13	N.A.	27.41	80.5	50.39	40.96
Indiana Michigan Power Co.	9.22	11.53	13.4	20.25	22.63	22.02	64.41	57	40.59
Indiana-Kentucky Electric Corp.	13.99	15.07	5.4	N.A.	19.39	19.39	N.A.	N.A.	N.A.
Indianapolis Power & Light Co.	10.99	11.98	5	64.88	15.98	16.8	61.17	65.37	45.61
Kentucky Power Co.	12.02	13.24	3.33	22.29	15.35	19.13	50.92	52.52	32.27
Kentucky Utilities Co.	15.98	16.63	3.22	18.18	19.2	18.93	46.4	44.92	35.18
Kingsport Power Co.	N.A.	N.A.	N.A.	29.44	N.A.	29.44	48.18	49.51	32.71
Louisville Gas & Electric Co.	12.39	13.38	4.98	20.4	17.37	18.02	58.26	53.84	37.99
Monongahela Power Co.	11.62	12.4	6.91	46.66	18.52	25.87	71.85	58.19	37.11
Northern Indiana Public Service Co.	15.19	16.36	5.84	31.07	21.03	23.35	94.44	80.97	42.37
Ohio Edison Co.	4.13	8.23	38.88	31.95	43.01	34.61	89.02	82.38	47.45
Ohio Power Co.	11.61	12.92	5.69	18.04	17.3	17.6	66.03	55.93	36.54
Ohio Valley Electric Corp.	12	13.09	5.1	29.45	17.1	23.56	N.A.	N.A.	356.88
PSI Energy Inc.	14.14	15.62	4.14	41.27	18.28	23.28	66.92	52.4	37.24
Pennsylvania Power Co.	4.09	8.29	21.04	31.96	25.13	28.52	90.04	76.75	53.79
Potomac Edison Co.	0	0	27.65	37.84	27.65	36.38	67.98	59.73	37.93
Southern Indiana Gas & Electric Co.	13.31	14.59	6.51	3.81	19.81	13.67	73.39	58.16	38.84
Toledo Edison Co.	6.9	14.57	54.29	32.24	61.19	42.11	90.21	87.19	41.61
Union Light Heat & Power Co.	N.A.	N.A.	N.A.	37.77	N.A.	37.77	64.88	58.8	50.49
West Penn Power Co.	N.A.	N.A.	N.A.	32.46	N.A.	32.54	62.57	52.96	39.54
Wheeling Power Co.	N.A.	N.A.	N.A.	26.91	N.A.	26.92	63.31	54.88	34.06
ECAR average	11.99	13.61	8.11	50.47	20.1	31.7	70.5	63.32	42.1
Standard & Poor's average	15.57	16.96	7.07	46.36	22.65	33.46	83.94	76.55	44.42

N.A. -- Not applicable or available. MWh -- Megawatt hour.