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Mr. Jeff DeRouen
Executive Director
Kentucky Public Service Commission
211 Sower Boulevard
Frankfort, KY 40602

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PUBLIC SERVICE COMMISSION

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State Regulation and Rates
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Director - Rates
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September 2, 2009

RE: ***THE APPLICATION OF KENTUCKY UTILITIES COMPANY FOR CERTIFICATES OF PUBLIC CONVENIENCE AND NECESSITY AND APPROVAL OF ITS 2009 COMPLIANCE PLAN FOR RECOVERY BY ENVIRONMENTAL SURCHARGE***
CASE NO. 2009-00197

Dear Mr. DeRouen:

Please find enclosed and accept for filing the original and eight (8) copies of the Response of Kentucky Utilities Company to the Initial Data Request of Commission Staff dated August 19, 2009, in the above-referenced matter.

Also enclosed are the original and ten (10) copies of a Petition for Confidential Protection for documents being filed in response to Question No. 24(a) of the Commission Staff's Initial Data Request in the above-referenced matter.

Should you have any questions concerning the enclosed, please contact me at your convenience.

Sincerely,

Robert M. Conroy

Enclosures

cc: Parties of Record

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

APPLICATION OF KENTUCKY UTILITIES	)	
COMPANY FOR CERTIFICATES OF PUBLIC	)	
CONVENIENCE AND NECESSITY AND	)	**CASE NO.**
APPROVAL OF ITS 2009 COMPLIANCE PLAN	)	**2009-00197**
FOR RECOVERY BY ENVIRONMENTAL	)	
SURCHARGE	)	

RESPONSE OF
KENTUCKY UTILITIES COMPANY
TO
INITIAL DATA REQUEST OF COMMISSION STAFF
DATED AUGUST 19, 2009

FILED: September 2, 2009

VERIFICATION

COMMONWEALTH OF KENTUCKY)
) SS:
COUNTY OF JEFFERSON)

The undersigned, **Lonnie E. Bellar**, being duly sworn, deposes and says he is Vice President, State Regulation and Rates for Kentucky Utilities Company and an employee of E.ON U.S. Services, Inc., and that has personal knowledge of the matters set forth in the foregoing testimony, and that the answers contained therein are true and correct to the best of his information, knowledge and belief.

Lonnie E. Bellar

LONNIE E. BELLAR

Subscribed and sworn to before me, a Notary Public in and before said County and State, this 2nd day of September 2009.

Tammy J. Elzy (SEAL)

Notary Public

My Commission Expires:

November 9, 2010

VERIFICATION

COMMONWEALTH OF KENTUCKY)
) SS:
COUNTY OF JEFFERSON)

The undersigned, **John N. Voyles, Jr.,** being duly sworn, deposes and says he is Vice President, Transmission and Generation Services for Kentucky Utilities Company and an employee of E.ON U.S. Services, Inc., and that he has personal knowledge of the matters set forth in the foregoing testimony, and the answers contained therein are true and correct to the best of his information, knowledge and belief.

John N Voyles Jr

John N. Voyles, Jr.

Subscribed and sworn to before me, a Notary Public in and before said County and State, this 2nd day of September 2009.

Tammy J. Ely (SEAL)
Notary Public

My Commission Expires:

November 9, 2010

VERIFICATION

COMMONWEALTH OF KENTUCKY)) SS: COUNTY OF JEFFERSON)

The undersigned, **Daniel K. Arbough**, being duly sworn, deposes and says he is Treasurer for Kentucky Utilities Company and an employee of E.ON U.S. Services, Inc., and that has personal knowledge of the matters set forth in the foregoing testimony, and that the answers contained therein are true and correct to the best of his information, knowledge and belief.

DANIEL K. ARBOUGH

Subscribed and sworn to before me, a Notary Public in and before said County and State, this 2nd day of September 2009.

Tammy J. Elzy (SEAL)
Notary Public

My Commission Expires:

November 9, 2010

VERIFICATION

COMMONWEALTH OF KENTUCKY)
) SS:
COUNTY OF JEFFERSON)

The undersigned, **Shannon L. Charnas**, being duly sworn, deposes and says she is Director, Utility Accounting and Reporting for E.ON U.S. Services Inc., that she has personal knowledge of the matters set forth in the foregoing testimony, and the answers contained therein are true and correct to the best of her information, knowledge and belief.

Shannon L Charnas

SHANNON L. CHARNAS

Subscribed and sworn to before me, a Notary Public in and before said County and State, this 2nd day of September 2009.

Tammy J. Elzy (SEAL)
Notary Public

My Commission Expires:

November 9, 2010

VERIFICATION

COMMONWEALTH OF KENTUCKY)
) SS:
COUNTY OF JEFFERSON)

The undersigned, **Robert M. Conroy**, being duly sworn, deposes and says he is the Director – Rates for E.ON U.S. Services Inc., and that he has personal knowledge of the matters set forth in the foregoing testimony, and the answers contained therein are true and correct to the best of his information, knowledge and belief.

ROBERT M. CONROY

Subscribed and sworn to before me, a Notary Public in and before said County and State, this 2nd day of September 2009.

Tammy J. Elzy
(SEAL)
Notary Public

My Commission Expires:

November 9, 2010

VERIFICATION

COMMONWEALTH OF KENTUCKY)
) SS:
COUNTY OF JEFFERSON)

The undersigned, **Charles R. Schram**, being duly sworn, deposes and says he is Director, Energy Planning, Analysis & Forecasting for E.ON U.S. Services, Inc., and that he has personal knowledge of the matters set forth in the foregoing testimony, and the answers contained therein are true and correct to the best of his information, knowledge and belief.

Charles R. Schram

CHARLES R. SCHRAM

Subscribed and sworn to before me, a Notary Public in and before said County and State, this 2nd day of September 2009.

Tammy J. Elzy (SEAL)
Notary Public

My Commission Expires:

November 9, 2010

KENTUCKY UTILITIES COMPANY

**Response to Initial Data Request of Commission Staff
Dated August 19, 2009**

Case No. 2009-00197

Question No. 1

Witness: Lonnie E. Bellar / Daniel K. Arbough

Q-1. Refer to page 8 of the Direct Testimony of Lonnie E. Bellar ("Bellar Testimony").

a. Describe KU's plans for the mix of debt and equity it plans to use to finance the proposed facilities, including, but not limited to, whether it believes there is a range of debt-to-equity that is required in order to maintain its current credit rating.

b. Describe the tax-exempt financing referenced beginning on line 6, including, but not limited to:

(1) Whether such debt would be limited to pollution control bonds issued through either Trimble County, Carroll County or Mercer County; and

(2) The level of savings that could be expected through tax-exempt financing.

A-1. a. The Company intends to finance these facilities with proportions of debt and equity that are consistent with existing ratios. Funding on this basis should enable the Company to maintain the existing debt ratings. Moody's recently published the attached article entitled "Regulated Electric and Gas Utilities" wherein they cite target ratios for various rating levels. KU's current rating from Moody's is A3 which would imply the need to maintain a debt/total capitalization ratio of 35% to 45%. The Company has targeted a rating of A from S&P which implies a debt/total capitalization ratio of not more than 50%. The current rating of BBB+ from S&P would imply debt/total capital ratio of 45% to 60%.

b. (1) To the extent the Company has qualifying expenses and can obtain the required allocations from the state Finance Cabinet, the referenced tax-exempt financing would be in the form of pollution control bonds issued by the county in which the assets are located.

(2) The savings realized by tax-exempt bonds are subject to market conditions at the time the bonds are issued. The Company would expect tax-exempt bonds to result in savings over other types of financing options of between 25 and 35% of total interest expense. However, in recent months those savings have been less as the taxable bond market has rebounded from the financial crisis much more rapidly than the tax-exempt market. In recent months, there have been times when the tax-exempt market has not provided any benefit.

Customers will realize any financing savings through the routine operation of the ECR mechanism.

Attachment to Response to Question No. 1 – “Regulated Electric and Gas Utilities” article
Responding Witness – Lonnie E. Bellar / Daniel K. Arbough

Rating Methodology

Moody's Global Infrastructure Finance

August 2009

Regulated Electric and Gas Utilities

Table of Contents:

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(Continued on back page)

Summary

This rating methodology provides guidance on Moody's approach to assigning credit ratings to electric and gas utility companies worldwide whose credit profile is influenced to a large degree by the presence of regulation. It replaces the Global Regulated Electric Utilities methodology published in March 2005 and the North American Regulated Gas Distribution Industry (Local Distribution Companies) methodology published in October 2006. While reflecting similar core principles as these previous methodologies, this updated framework incorporates refinements that better reflect the changing dynamics of the regulated electric and gas industry and the way Moody's applies its industry methodologies.

The goal of this rating methodology is to assist investors, issuers, and other interested parties in understanding how Moody's arrives at company-specific ratings, what factors we consider most important for this sector, and how these factors map to specific rating outcomes. Our objective is for users of this methodology to be able to estimate a company's ratings (senior unsecured ratings for investment-grade issuers and Corporate Family Ratings for speculative-grade issuers) within two alpha-numeric rating notches.

Regulated electric and gas companies are a diverse universe in terms of business model (ranging from vertically integrated to unbundled generation, transmission and/or distribution entities) and regulatory environment (ranging from stable and predictable regulatory regimes to those that are less developed or undergoing significant change). In seeking to differentiate credit risk among the companies in this sector, Moody's analysis focuses on four key rating factors that are central to the assignment of ratings for companies in the sector. The four key rating factors encompass nine specific elements (or sub-factors), each of which map to specific letter ratings (see Appendix A). The four factors are as follows:

1. Regulatory Framework
2. Ability to Recover Costs and Earn Returns
3. Diversification
4. Financial Strength and Liquidity

Moody's Investors Service

Regulated Electric and Gas Utilities

This methodology pertains to regulated electric and gas utilities and excludes regulated electric and gas networks (companies primarily engaged in the transmission and/or distribution of electricity and/or natural gas that do not serve retail customers) and unregulated utilities and power companies, which are covered by separate rating methodologies. Municipal utilities and electric cooperatives are also excluded and covered by separate rating methodologies.

In Appendix A of this methodology, we have included a detailed rating grid for the companies covered by the methodology. For each company, the grid maps each of these key rating factors and shows an indicated alpha-numeric rating based on the results from the overall combination of the factors (see Appendix B). We note, however, that many companies will not match each dimension of the analytical framework laid out in the rating grid exactly and that from time to time a company's performance on a particular rating factor may fall outside the expected range for a company at its rating level. These companies are categorized as "outliers" for that rating factor. We discuss some of the reasons for these outliers in this methodology as well as in published credit opinions and other company-specific analysis.

The purpose of the rating grid is to provide a reference tool that can be used to approximate credit profiles within the regulated electric and gas utility sector. The grid provides summarized guidance on the factors that are generally most important in assigning ratings to the sector. While the factors and sub-factors within the grid are designed to capture the fundamental rating drivers for the sector, this grid does not include every rating consideration and does not fit every business model equally. Therefore, we outline additional considerations that may be appropriate to apply in addition to the four rating factors. Moody's also assesses other rating factors that are common across all industries, such as event risk, off-balance sheet risk, legal structure, corporate governance, and management experience and credibility. Furthermore, most of our sub-factor mapping uses historical financial results to illustrate the grid while our ratings also consider forward looking expectations. As such, the grid-indicated rating is not expected to always match the actual rating of each company. The text of the rating methodology provides insights on the key rating considerations that are not represented in the grid, as well as the circumstances in which the rating effect for a factor might be significantly different from the weight indicated in the grid.

Readers should also note that this methodology does not attempt to provide an exhaustive list of every factor that can be relevant to a utility's ratings. For example, our analysis covers factors that are common across all industries (such as coverage metrics, debt leverage, and liquidity) as well as factors that can be meaningful on a company or industry specific basis (such as regulation, capital expenditure needs, or carbon exposure).

This publication includes the following sections:

- **About the Rated Universe**: An overview of the regulated electric and gas industries
- **About the Rating Methodology**: A description of our rating methodology, including a detailed explanation of each of the key factors that drive ratings
- **Assumptions and Limitations**: Comments on the rating methodology's assumptions and limitations, including a discussion of other rating considerations that are not included in the grid

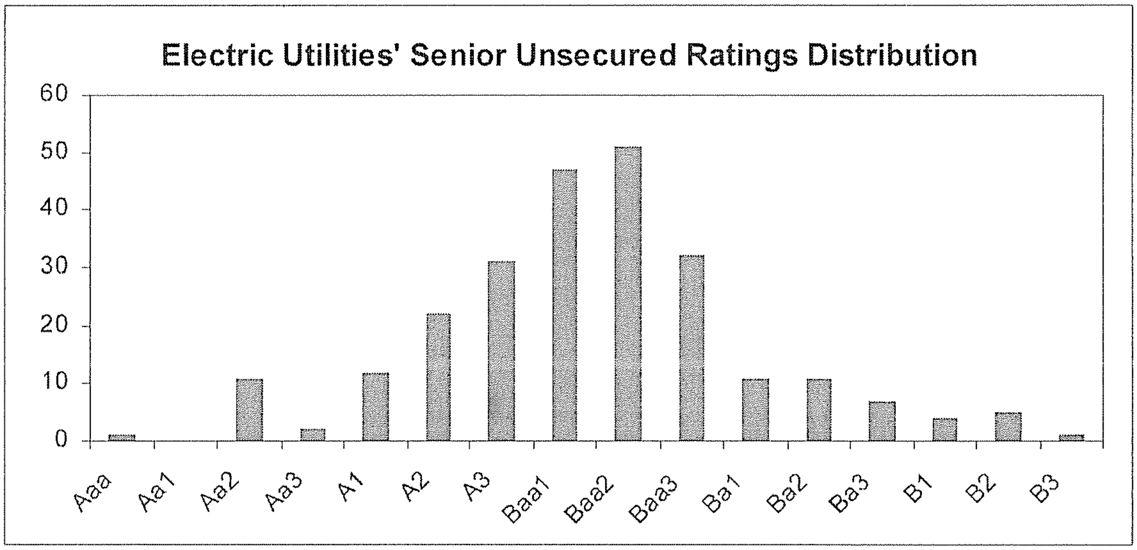
In the appendices, we also provide tables that illustrate the application of the methodology grid to 30 representative electric and gas utility companies with explanatory comments on some of the more significant differences between the grid-implied rating and our actual rating (Appendix C). We also provide definitions of key ratios (Appendix D), an industry overview (Appendix E) and a discussion of the key issues facing the industry over the intermediate term (Appendix F) and regional considerations (Appendix G).

About the Rated Universe

The rating methodology covers investor-owned and commercially oriented government owned companies worldwide that are engaged in the production, transmission, distribution and/or sale of electricity and/or natural gas. It covers a wide variety of companies active in the sector, including vertically integrated utilities, transmission and distribution companies, some U.S. transmission-only companies, and local gas distribution companies (LDCs). For the LDCs, we note that this methodology is concerned principally with operating utilities regulated by their local jurisdictions and not with gas companies that have significant non-utility businesses[1]. In addition, this methodology includes both holding companies as well as operating companies. For holding companies, actual ratings may be lower than methodology grid-implied ratings due to the structural subordination of the holding company debt to the operating company debt. In order for a utility to be covered by this methodology, the company must be an investor-owned or commercially oriented government owned entity and be subject to some degree of government regulation or oversight. This methodology excludes regulated electric and gas networks, electric generating companies[2] and independent power producers operating predominantly in unregulated power markets, municipally owned utilities, electric cooperative utilities, and power projects, which are covered in separate rating methodologies.

The rated universe includes approximately 250 entities that are either utility operating companies or a parent holding company with one or more utility company subsidiaries that operate predominantly in the electric and gas utility business. They account for about US$650 billion of total outstanding long-term debt instruments. In general, ratings used in this methodology are the Senior Unsecured ("SU") rating for investment grade companies, the Corporate Family Rating ("CFR") for non-investment grade companies, and the Baseline Credit Assessment ("BCA") for Government Related Issuers (GRI). A subset of 30 of these entities is included in the methodology, representing a sampling of the universe to which this methodology applies.

Geographically, this methodology covers companies in the Americas, Europe, Middle East, Africa, Japan, and the Asia/Pacific region. The ratings spectrum for the sector ranges from Aaa to B3, with the actual rating distribution of the issuers included (both holding companies and operating companies) shown on the following table:



Although all of these companies are affected to some degree by government regulation or oversight, country-by-country regulatory differences and cultural and economic characteristics are also important credit considerations. There is little consistency in the approach and application of regulatory frameworks around the world. Some regulatory frameworks are highly supportive of the utilities in their jurisdictions, in some cases offering implied sovereign support to ensure reliability of electric supply. Other regulatory frameworks are less supportive, more unpredictable or affected by political influence that can increase uncertainty and negatively affect overall credit quality.

1 These companies are assessed under the rating methodology "North American Diversified Natural Gas Transmission and Distribution Companies", March 2007.

2 The six Korean generation companies are included in this methodology as they are subject to regulation and Moody's views them and their 100% parent and sole off-taker KEPCO on a consolidated basis. The Brazilian generation companies are included as they are also subject to regulatory intervention.

About this Rating Methodology

Moody's approach to rating companies in the regulated electric and gas utility sector, as outlined in this rating methodology, incorporates the following steps:

1. Identification of the Key Rating Factors

In general, Moody's rating committees for the regulated electric and gas utility sector focus on a number of key rating factors which we identify and quantify in this methodology. A change in one or more of these factors, depending on its weighting, is likely to influence a utility's overall business and financial risk. We have identified the following four key rating factors and nine sub-factors when assigning ratings to regulated electric and gas utility issuers:

Rating Factor / Sub-Factor Weighting - Regulated Utilities

Broad Rating Factors	Broad Rating Factor Weighting	Rating Sub-Factor	Sub-Factor Weighting
Regulatory Framework	25%		25%
Ability to Recover Costs and Earn Returns	25%		25%
Diversification	10%	Market Position	5%*
		Generation and Fuel Diversity	5%**
Financial Strength, Liquidity and Key Financial Metrics	40%	Liquidity	10%
		CFO pre-WC + Interest/ Interest	7.5%
		CFO pre-WC / Debt	7.5%
		CFO pre-WC - Dividends / Debt	7.5%
		Debt/Capitalization or Debt / Regulated Asset Value	7.5%
Total	**100%**		**100%**

*10% weight for issuers that lack generation; **0% weight for issuers that lack generation

These factors are critical to the analysis of regulated electric and gas utilities and, in most cases, can be benchmarked across the industry. The discussion begins with a review of each factor and an explanation of its importance to the rating.

2. Measurement of the Key Rating Factors

We next explain the elements we consider and the metrics we use to measure relative performance on each of the four factors. Some of these measures are quantitative in nature and can be specifically defined. However, for other factors, qualitative judgment or observation is necessary to determine the appropriate rating category.

Moody's ratings are forward looking and attempt to rate through the industry's characteristic volatility, which can be caused by weather variations, fuel or commodity price changes, cost deferrals, or reasonable delays in regulatory recovery. The rating process also makes extensive use of historic financial statements. Historic results help us understand the pattern of a utility's financial and operating performance and how a utility compares to its peers. While rating committees and the rating process use both historical and projected financial results, this document makes use only of historic data, and does so solely for illustrative purposes. All financial measures incorporate Moody's standard adjustments to income statement, cash flow statement, and balance sheet amounts for (among other things) underfunded pension obligations and operating leases.

3. Mapping Factors to Rating Categories

After identifying the measurement criteria for each factor, we match the performance of each factor and sub-factor to one of Moody's broad rating categories (Aaa, Aa, A, Baa, Ba, and B). In this report, we provide a range or description for each of the measurement criteria. For example, we specify what level of CFO pre-WC plus Interest/Interest is generally acceptable for an A credit versus a Baa credit, etc.

4. Mapping Issuers to the Grid and Discussion of Grid Outliers

For each factor and sub-factor, we provide a table showing how a subset of the companies covered by the methodology maps within the specific factors and sub-factors. We recognize that any given company may perform higher or lower on a given factor than its actual rating level will otherwise indicate. These companies are identified as "outliers" for that factor. A company whose performance is two or more broad rating categories higher than its rating is deemed a positive outlier for that factor. A company whose performance is two or more broad rating categories below is deemed a negative outlier. We also discuss the general reasons for such outliers for each factor.

5. Discussion of Assumptions, Limitations and Other Rating Considerations

This section discusses limitations in the use of the grid to map against actual ratings as well as limitations and key assumptions that pertain to the overall rating methodology.

6. Determining the Overall Grid-Indicated Rating

To determine the overall rating, each of the factors and sub-factors is converted into a numeric value based on the following scale:

Ratings Scale

Aaa	Aa	A	Baa	Ba	B
1	3	6	9	12	15

Each sub-factor's numeric value is multiplied by an assigned weight and then summed to produce a composite weighted-average score. The total sum of the factors is then mapped to the ranges specified in the table below, and the indicated alpha-numeric rating is determined based on where the total score falls within the ranges.

Factor Numerics

Composite Rating

Indicated Rating	Aggregate Weighted Factor Score
Aaa	< 1.5
Aa1	1.5 < 2.5
Aa2	2.5 < 3.5
Aa3	3.5 < 4.5
A1	4.5 < 5.5
A2	5.5 < 6.5
A3	6.5 < 7.5
Baa1	7.5 < 8.5
Baa2	8.5 < 9.5
Baa3	9.5 < 10.5
Ba1	10.5 < 11.5
Ba2	11.5 < 12.5
Ba3	12.5 < 13.5
B1	13.5 < 14.5
B2	14.5 < 15.5
B3	15.5 < 16.5

For example, an issuer with a composite weighting factor score of 8.2 would have a Baa1 grid-indicated rating. We use a similar procedure to derive the grid-indicated ratings in the tables embedded in the discussion of each of the four broad rating categories.

The Key Rating Factors

Moody's analysis of electric and gas utilities focuses on four broad factors:

1. Regulatory Framework
2. Ability to Recover Costs and Earn Returns
3. Diversification
4. Financial Strength and Liquidity

Rating Factor 1: Regulatory Framework (25%)

Why it Matters

For a regulated utility, the predictability and supportiveness of the regulatory framework in which it operates is a key credit consideration and the one that differentiates the industry from most other corporate sectors. The most direct and obvious way that regulation affects utility credit quality is through the establishment of prices or rates for the electricity, gas and related services provided (revenue requirements) and by determining a return on a utility's investment, or shareholder return. The latter is largely addressed in Factor 2, Ability to Recover Cost and Earn Returns, discussed below. However, in addition to rate setting, there are numerous other less visible or more subtle ways that regulatory decisions can affect a utility's business position. These can include the regulators' ability to pre-approve recovery of investments for new generation, transmission or distribution; to allow the inclusion of generation asset purchases in utility rate bases; to oversee and ultimately approve utility mergers and acquisitions; to approve fuel and purchased power recovery; and to institute or increase ring-fencing provisions.

How We Measure It for the Grid

For a regulated utility company, we consider the characteristics of the regulatory environment in which it operates. These include how developed the regulatory framework is; its track record for predictability and stability in terms of decision making; and the strength of the regulator's authority over utility regulatory issues. A utility operating in a stable, reliable, and highly predictable regulatory environment will be scored higher on this factor than a utility operating in a regulatory environment that exhibits a high degree of uncertainty or unpredictability. Those utilities operating in a less developed regulatory framework or one that is characterized by a high degree of political intervention in the regulatory process will receive the lowest scores on this factor. Consideration is given to the substance of any regulatory ring fencing provisions, including restrictions on dividends; restrictions on capital expenditures and investments; separate financing provisions; separate legal structures; and limits on the ability of the regulated entity to support its parent company in times of financial distress. The criteria for each rating category are outlined in the factor description within the rating grid.

For regulated electric utilities with some unregulated operations, consideration will be given to the competitive and business position of these unregulated operations[3]. Moody's views unregulated operations that have minimal or limited competition, large market shares, and statutorily protected monopoly positions as having substantially less risk than those with smaller market shares or in highly competitive environments. Those businesses with the latter characteristics usually face a higher likelihood of losing customers, revenues, or market share. For electric utilities with a significant amount of such unregulated operations, a lower score could be assigned to this factor than would be if the utility had solely regulated operations.

Moody's views the regulatory risk of U.S. utilities as being higher in most cases than that of utilities located in some other developed countries, including Japan, Australia, and Canada The difference in risk reflects our view that individual state regulation is less predictable than national regulation; a highly fragmented market in the U.S. results in stronger competition in wholesale power markets; U.S. fuel and power markets are more

[3] For diversified gas companies, the "North American Diversified Natural Gas Transmission and Distribution Company" rating methodology is applied.

volatile; there is a low likelihood of extraordinary political action to support a failing company in the U.S.; holding company structures limit regulatory oversight; and overlapping or unclear regulatory jurisdictions characterize the U.S. market. As a result, no U.S. utilities, except for transmission companies subject to federal regulation, score higher than a single A in this factor.

The scores for this factor replace the classifications we had been using to assess a utility's regulatory framework, namely, the Supportiveness of Regulatory Environment (SRE) framework, outlined in our previous rating methodology (Global Regulated Electric Utilities, March 2005), which we are phasing out. Generally speaking, an SRE 1 score from our previous methodology would roughly equate to Aaa or Aa ratings in this methodology; an SRE 2 score to A or high Baa; an SRE 3 score to low Baa or Ba, and an SRE 4 score to a B. For U.S. and Canadian LDCs, this factor corresponds to the "Regulatory Support" and "Ring-fencing" factors in our previous methodology (North American Regulated Gas Distribution, October 2006).

Factor 1 – Regulatory Framework (25%)

Aaa	Aa	A	Baa	Ba	B
Regulatory framework is fully developed, has a long-track record of being predictable and stable, and is highly supportive of utilities. Utility regulatory body is a highly rated sovereign or strong independent regulator with unquestioned authority over utility regulation that is national in scope.	Regulatory framework is fully developed, has been mostly predictable and stable in recent years, and is mostly supportive of utilities. Utility regulatory body is a sovereign, sovereign agency, provincial, or independent regulator with authority over most utility regulation that is national in scope.	Regulatory framework is fully developed, has above average predictability and reliability, although is sometimes less supportive of utilities. Utility regulatory body may be a state commission or national, state, provincial or independent regulator.	Regulatory framework is a) well-developed, with evidence of some inconsistency or unpredictability in the way framework has been applied, or framework is new and untested, but based on well-developed and established precedents, or b) jurisdiction has history of independent and transparent regulation in other sectors. Regulatory environment may sometimes be challenging and politically charged.	Regulatory framework is developed, but there is a high degree of inconsistency or unpredictability in the way the framework has been applied. Regulatory environment is consistently challenging and politically charged. There has been a history of difficult or less supportive regulatory decisions, or regulatory authority has been or may be challenged or eroded by political or legislative action.	Regulatory framework is less developed, is unclear, is undergoing substantial change or has a history of being unpredictable or adverse to utilities. Utility regulatory body lacks a consistent track record or appears unsupportive, uncertain, or highly unpredictable. May be high risk of nationalization or other significant government intervention in utility operations or markets.

Rating Factor 2: Ability to Recover Costs and Earn Returns (25%)

Why It Matters

Unlike Factor 1, which considers the general regulatory framework under which a utility operates and the overall business position of a utility within that regulatory framework, this factor addresses in a more specific manner the ability of an individual utility to recover its costs and earn a return. The ability to recover prudently incurred costs in a timely manner is perhaps the single most important credit consideration for regulated utilities as the lack of timely recovery of such costs has caused financial stress for utilities on several occasions. For example, in four of the six major investor-owned utility bankruptcies in the United States over the last 50 years, regulatory disputes culminated in insufficient or delayed rate relief for the recovery of costs and/or capital investment in utility plant. The reluctance to provide rate relief reflected regulatory commission concerns about the impact of large rate increases on customers as well as debate about the appropriateness of the relief being sought by the utility and views of imprudency. Currently, the utility industry's sizable capital expenditure requirements for infrastructure needs will create a growing and ongoing need for rate relief for recovery of these expenditures at a time when the global economy has slowed.

How We Measure It for the Grid

For regulated utilities, the criteria we consider include the statutory protections that are in place to insure full and timely recovery of prudently incurred costs. In its strongest form, these statutory protections provide unquestioned recovery and preclude any possibility of legal or political challenges to rate increases or cost recovery mechanisms. Historically, there should be little evidence of regulatory disallowances or delays to rate increases or cost recovery. These statutory protections are most often found in strongly supportive and protected regulatory environments such as Japan, for example, where the utilities in that country receive a score of Aa for this factor.

More typically, however, and as is characteristic of most utilities in the U.S., the ability to recover costs and earn authorized returns is less certain and subject to public and sometimes political scrutiny. Where automatic cost recovery or pass-through provisions exist and where there have been only limited instances of regulatory challenges or delays in cost recovery, a utility would likely receive a score of A for this factor. Where there may be a greater tendency for a regulator to challenge cost recovery or some history of regulators disallowing or delaying some costs, a utility would likely receive a Baa rating for this factor. Where there are no automatic cost recovery provisions, a history of unfavorable rate decisions, a politically charged regulatory environment, or a highly uncertain cost recovery environment, lower scores for this factor would apply.

For regulated electric utilities that have some unregulated operations, we assess the likelihood that the utility will be able to pass on costs of its unregulated businesses to unregulated customers. Among the criteria we use to judge this factor include the number and types of different businesses the company is in; its market share in these businesses; whether there are significant barriers to entry for new competitors; and the degree to which the utility is vertically integrated. Those utilities with several businesses with large market shares are generally in a better position to pass on their costs to unregulated customers. Those utilities that have lower market shares in their unregulated activities or are in businesses with few barriers to entry will likely be more at risk in passing on costs, and thus would receive lower scores. A high proportion of unregulated businesses or a higher risk of passing on costs to unregulated customers could result in a lower score for this factor than would apply if the business was completely regulated.

For U.S. and Canadian LDCs, this factor addresses the "Sustainable Profitability" and "Regulatory Support" assessments in the previous LDC rating methodology. While LDCs' authorized returns are comparable to those for their electric counterparts, the smaller, more mature LDCs tend to face less regulatory challenges. Purchased Gas Adjustment mechanisms are the norm and they have made strides in implementing alternative rate designs that decouple revenues from volumes sold.

Factor 2 – Ability to Recover Costs and Earn Returns (25%)

Aaa	Aa	A	Baa	Ba	B
Rate/tariff formula allows unquestioned full and timely cost recovery, with statutory provisions in place to preclude any possibility of challenges to rate increases or cost recovery mechanisms.	Rate/tariff formula generally allows full and timely cost recovery. Fair return on all investments. Minimal challenges by regulators to companies' cost assumptions; consistent track record of meeting efficiency tests.	Rate/tariff reviews and cost recovery outcomes are fairly predictable (with automatic fuel and purchased power recovery provisions in place where applicable), with a generally fair return on investments. Limited instances of regulatory challenges; although efficiency tests may be more challenging; limited delays to rate or tariff increases or cost recovery.	Rate/tariff reviews and cost recovery outcomes are usually predictable, although application of tariff formula may be relatively unclear or untested. Potentially greater tendency for regulatory intervention, or greater disallowance (e.g. challenging efficiency assumptions) or delaying of some costs (even where automatic fuel and purchased power recovery provisions are applicable).	Rate/tariff reviews and cost recovery outcomes are inconsistent, with some history of unfavorable regulatory decisions or unwillingness by regulators to make timely rate changes to address market volatility or higher fuel or purchased power costs. AND/OR Tariff formula may not take into account all cost components; investment are not clearly or fairly remunerated.	Difficult or highly uncertain rate and cost recovery outcomes. Regulators may engage in second-guessing of spending decisions or deny rate increases or cost recovery needed by utilities to fund ongoing operations, or high likelihood of politically motivated interference in the rate/tariff review process. AND/OR Tariff formula may not cover return on investments, only cash operating costs may be remunerated.

Rating Factor 3 - Diversification (10%)

Why It Matters

Diversification of overall business operations helps to mitigate the risk that any one part of the company will have a severe negative impact on cash flow and credit quality. In general, a balance among several different businesses, geographic regions, regulatory regimes, generating plants, or fuel sources will diminish concentration risk and reduce the risk that a company will experience a sudden or rapid deterioration in its overall creditworthiness because of an adverse development specific to any one part of its operations.

How We Measure It For the Grid

For transmission and distribution utilities, local gas distribution companies, and other companies without significant generation, the key criterion we use is the diversity of their operations among various markets, geographic regions or regulatory regimes. For these utilities, the first set of criteria, labeled market diversification, account for the full 10% weighting for this factor. A predominately T&D utility with a high degree of diversification in terms of market and/or regulatory regime is less likely to be affected by adverse or unexpected developments in any one of these markets or regimes, and thus will receive the highest scores for this factor. Smaller T&D utilities operating in a limited market area or under the jurisdiction of a single regulatory regime will score lower on the factor, with those that are concentrated in an emerging market or riskier environment receiving the lowest scores.

For vertically integrated utilities with generation, the diversification factor is broadened to include not only the criteria discussed above, but also takes into consideration the diversity of their generating assets and the type of fuel sources which they rely on. An additional but somewhat related consideration is the degree to which the utility is exposed to (or insulated from) commodity price changes. A utility with a highly diversified fleet of generating assets using different types of fuels is generally better able to withstand changes in the price of a particular fuel or additional costs required for particular assets, such as more stringent environmental compliance requirements, and thus would receive a higher rating for this sub-factor. Those utilities with more limited diversification or that are more reliant on a single type of generation and fuel source (measured by energy produced) will be scored lower on this sub-factor. Similarly, those utilities with a high reliance on coal and other carbon emitting generating resources will be scored lower on this factor due to their vulnerability to potential carbon regulations and accompanying carbon costs.

Generally, only the largest vertically integrated utilities or transmission companies with substantial operations that are multinational or national in scope, or whose operations encompass a substantial region within a single country, will receive scores in the highest Aaa or Aa categories for this factor. In the U.S., most of the largest multi-state or multi-regional utilities are scored in the A category, most of the larger single state utilities are scored Baa, and smaller utilities operating in a single state or within a single city are scored Ba. A utility may also be scored higher if it is a combination electric and gas utility, which enhances diversification.

The diversification factor was not included in the previous North American LDC methodology. Most LDCs are small and tend to have little geographic and regulatory diversity. However, they tend to be highly stable due to their customer base and margins that comprise primarily of a large number of residential and small commercial customers that are captive to the utility. This customer composition tends to result in a more stable operating performance than those that have concentrations in certain industrial customers that are prone to cyclicality or to bypassing the LDC to obtain gas directly from a pipeline. Pure LDCs are scored under the "Market Position" sub-factor for a full 100% under this factor. As with transmission and distribution utilities, no scores are given for "Fuel/Generation Diversification" as this sub-factor would not be applicable.

Factor 3: Diversification (10%)

	Aaa	Aa	A	Baa	Ba	B	Sub-Factor Weighting
Market Position	A high degree of multinational/ regional diversification in terms of market and/or regulatory regime.	Material operations in more than three nations or geographic regions providing diversification of market and/or regulatory regime.	Material operations in two or three states, nations, or geographic regions and exhibits some diversification of market and/or regulatory regime.	Operates in a single state, nation, or economic region with low volatility with some concentration of market and/or regulatory regime.	Operates in a limited market area with material concentration in market and/or regulatory regime.	Operates in a single market which may be an emerging market or riskier environment, with high concentration risk.	5% *
Market Position	For LDCs, extremely low reliance on industrial customers and/or exceptionally large residential and commercial customer base and well above average growth.	For LDCs, very low reliance on industrial customers and/or very large residential and commercial customer base with very high growth.	For LDCs, low reliance on industrial customers and/or high residential and commercial customer base with high growth.	For LDCs, moderate reliance on industrial customers in defensive sectors, moderate residential and customer base.	For LDCs, high reliance on industrial customers in somewhat cyclical sectors, small residential and commercial customer base.	For LDCs, very high reliance on industrial customers in cyclical sectors, very small residential and commercial customer base.	
Generation and Fuel Diversity	A high degree of diversification in terms of generation and/or fuel source, well insulated from commodity price changes, no generation concentration, or 0-20% of generation from carbon fuels.	Some diversification in terms of generation and/or fuel source, affected only minimally by commodity price changes, little generation concentration, or 20-40% of generation from carbon fuels.	May have some concentration in one particular type of generation or fuel source, although mostly diversified, modest exposure to commodity price changes, or 40-55% of generation from carbon fuels.	Some reliance on a single type of generation or fuel source, limited diversification, moderate exposure to commodity prices, or 55-70% of generation from carbon fuels.	Operates with little diversification in terms of generation and/or fuel source, high exposure to commodity price changes, or 70-85% of generation from carbon fuels.	High concentration in a single type of generation or highly reliant on a single fuel source, little diversification, may be exposed to commodity price shocks, or 85-100% of generation from carbon fuels.	5% **

**10% weight for issuers that lack generation **0% weight for issuers that lack generation*

Rating Factor 4 – Financial Strength and Liquidity (40%)

Why It Matters

Since most electric and gas utilities are highly capital intensive, financial strength and liquidity are key credit factors supporting their long-term viability. Financial strength and liquidity are also important to the maintenance of good relationships with regulators, to assure adequate regulatory responsiveness to rate increase requests and for cost recovery, and to avoid the need for sudden or unexpected rate increases to avoid financial problems. Financial strength is also important due to the ongoing need to invest in generation, transmission, and distribution assets that often require substantial amounts of debt financing. Utilities are among the largest debt issuers in the world and typically require consistent access to the capital markets to assure adequate sources of funding and to maintain financial flexibility.

Although ratio analysis is a helpful way of comparing one company's performance to that of another, no single financial ratio can adequately convey the relative credit strength of these highly diverse companies. The relative strength of a company's financial ratios must take into consideration the level of business risk associated with the more qualitative factors in the methodology. *Companies with a lower business risk can have weaker credit metrics than those with higher business risk for the same rating category.*

Given the long-term nature of many of the capital intensive projects undertaken in the industry and the need to obtain regulatory recovery over an often multi-year time period, it is important to analyze both a utility's historical financial performance as well as its prospective future performance, which may be different from the historic measures. Scores under this factor may be higher or lower than what might be expected from historical results, depending on our view of expected future performance.

How We Measure It For the Grid

In addition to assigning a score for a utility's overall liquidity position and relative access to funding sources and the capital markets, we have identified four key core ratios that we consider the most useful in the analysis of regulated electric and gas utilities. The four ratios are the following:

- Cash from Operations (CFO) pre-Working Capital Plus Interest / Interest
- Cash from Operations (CFO) pre-Working Capital / Debt
- Cash from Operations (CFO) pre-Working Capital – Dividends / Debt
- Debt/Capitalization or Debt / Regulated Asset Value (RAV)

The use of Debt / Capitalization or Debt / Regulated Asset Value will depend largely on the regulatory regime in which the utility operates, as explained below. These credit metrics incorporate all of the standard adjustments applied by Moody's when analyzing financial statements, including adjustments for certain types of off-balance sheet financings and certain other reclassifications in the income statement and cash flow statement.

These cash flow based ratios replace the earnings based metrics in the previous "North American Local Gas Distribution Company" rating methodology, reducing the impact on the grid results from non-cash items, such as pension expense.

The ratio calculations utilized and published for the companies covered by this methodology (including the 30 representative electric and gas utility companies highlighted) are historical three-year averages for the years 2006-2008. Three-year averages are used in part to smooth out some of the year to year volatility in financial performance and financial statement ratios.

<u>Measurement Criteria</u>

Liquidity

Liquidity analysis is a key element in the financial analysis of electric and gas utilities and encompasses a company's ability to generate cash from internal sources, as well as the availability of external sources of financings to supplement these internal sources. Sources of funds are compared to a company's cash needs and other obligations over the next twelve months. The highest "Aaa" and "Aa" scores under this sub-factor would be assigned to those utilities that are financially robust under all or virtually all scenarios, with little to no need for external funding and with unquestioned or superior access to the capital markets. Most utilities, however, receive more moderate scores of between "A" and "Baa" in this sub-factor as most need to rely to some degree on external funding sources to finance capital expenditures and meet other capital needs. Below investment grade scores on the sub-factor are assigned to utilities with weak liquidity or those that rely heavily on debt to finance investments.

CFO pre-Working Capital Plus Interest/Interest or Cash Flow Interest Coverage

The cash flow interest coverage ratio is a basic measure of a utility's ability to cover the cost of its borrowed capital and is an important analytical tool in this highly capital intensive industry. The numerator in the ratio calculation is a measure of cash flow excluding working capital movements plus interest expense, which can vary in significance depending on the utility. The use of CFO pre-WC is more comprehensive than Funds from Operations (FFO) under U.S. Generally Accepted Accounting Principles (GAAP) since it also captures the changes in long-term regulatory assets and liabilities. However, under International Financial Reporting Standards (IFRS), the two measures are essentially the same. The denominator in the ratio calculation is interest expense, which incorporates our standard adjustments to interest expense, such as including capitalized interest and re-classifying the interest component of operating lease rental expense. In Brazil, the cash interest amount is adjusted by the variation of non-cash financial expenses derived from foreign exchange and inflation denominated debt.

CFO pre-Working Capital / Debt

This metric measures the cash generating ability of a utility compared to the aggregate level of debt on the balance sheet. This ratio is useful in comparing utilities, many of which maintain a significant amount of leverage in their capital structure. The debt calculation takes into consideration Moody's standard adjustments to balance sheet debt, such as for operating leases, underfunded pension liabilities, basket-adjusted hybrids, guarantees, and other debt-like items.

CFO pre-Working Capital – Dividends / Debt

This ratio is a measure of financial leverage as well as an indicator of the strength of a utility's cash flow after dividend payments are made. Dividend obligations of utilities are often substantial and can affect the ability of a utility to cover its debt obligations. The higher the level of retained cash flow relative to a utility's debt, the more cash the utility has to support its capital expenditure program. Moody's expects that even the financially strongest utilities will need to issue debt on a regular basis to maintain a target capital structure if their asset bases are growing. If a utility with an expanding asset base funds all of its capital expenditures with internally generated cash flow then, in the extreme, the utility's debt to capitalization will trend toward zero.

Debt/Capitalization or Debt/Regulated Asset Value or RAV

This ratio is a traditional measure of leverage and can be a useful way to gauge a utility's overall financial flexibility in light of its overall debt load. High debt to capitalization levels are not only an indicator of higher interest obligations, but can also limit the ability of a utility to raise additional financing if needed and can lead to leverage covenant violations in bank credit facilities or other financing agreements. The denominator of the debt / capitalization ratio includes Moody's standard adjustments, the most important of which for some utilities is the inclusion of deferred taxes in capitalization, which tempers the impact of our debt adjustment.

While debt/capitalization is used predominantly in the Americas, other regions may use a variation of this ratio, namely, debt/regulated asset value or RAV ratio. The regulated asset base is comprised of the physical assets that are used to provide regulated distribution services and the RAV represents the value on which the utility is permitted to earn a return. RAV can be calculated in various ways, using different rules that can be revised periodically, depending on the regulatory regime. Where RAV is calculated using consistent rules (i.e. Australia and Japan), debt/RAV is viewed as superior to debt / capitalization as a credit measure and will be used for this sub-factor. Where RAV does not exist (i.e. North America and most Asian countries) or the method of calculation is subject to arbitrary or unpredictable revisions, we use debt/capitalization.

Factor 4: Financial Strength, Liquidity and Key Financial Metrics (40%)

	Aaa	Aa	A	Baa	Ba	B	Sub-Factor Weighting
Liquidity	Financially robust under all scenarios with no need for external funding, unquestioned access to the capital markets, and excellent liquidity.	Financially robust under virtually all scenarios with little to no need for external funding, superior access to the capital markets, and very strong liquidity.	Financially strong under most scenarios with some reliance on external funding, solid access to the capital markets, and strong liquidity.	Some reliance on external funding and liquidity is more likely to be affected by external events, good access to the capital markets, and adequate liquidity under most scenarios.	Weak liquidity with more susceptibility to external shocks or unexpected events. Significant reliance on debt funding. Bank financing may be secured and there may be limited headroom under covenants.	Very weak liquidity with limited ability to withstand external shocks or unexpected events. Must use debt to finance investments. Bank financing is normally secured and there may be a high likelihood of breaching one or more covenants.	10%
CFO pre-WC + Interest/Interest	> 8.0x	6.0x - 8.0x	4.5x - 6.0x	2.7x - 4.5x	1.5x - 2.7x	< 1.5x	7.5%
CFO pre-WC/ Debt	> 40%	30% - 40%	22% - 30%	13% - 22%	5% - 13%	< 5%	7.5%
CFO pre-WC - Dividends/ Debt	> 35%	25% - 35%	17% - 25%	9% - 17%	0% - 9%	< 0%	7.5%
Debt/ Capitalization	< 25%	25% - 35%	35% - 45%	45% - 55%	55% - 65%	> 65%	7.5%
Debt/RAV	< 30%	30% - 45%	45% - 60%	60% - 75%	75% - 90%	> 90%	7.5%

Rating Methodology Assumptions and Limitations, and other Rating Considerations

The rating methodology grid incorporates a trade-off between simplicity that enhances transparency and greater complexity that would enable the grid to map more closely to actual ratings. The four rating factors in the grid do not constitute an exhaustive treatment of all of the considerations that are important for ratings of companies in the regulated electric and gas utility sector. In addition, our ratings incorporate expectations for future performance, while the financial information that is used to illustrate the mapping in the grid is mainly historical. In some cases, our expectations for future performance may be impacted by confidential information that we cannot publish. In other cases, we estimate future results based upon past performance, industry trends, and other factors. In either case, we acknowledge that estimating future performance is subject to the risk of substantial inaccuracy.

In choosing metrics for this rating methodology grid, we did not include certain important factors that are common to all companies in any industry, such as the quality and experience of management, assessments of corporate governance, financial controls, and the quality of financial reporting and information disclosure. The assessment of these factors can be highly subjective and ranking them by rating category in a grid would in some cases suggest too much precision in the relative ranking of particular issuers against all other issuers that are rated in various industry sectors.

Ratings may include additional factors that are difficult to quantify or that only have a meaningful effect in differentiating credit quality in some cases. Such factors include environmental obligations, nuclear decommissioning trust obligations, financial controls, and emerging market risk, where ratings might be constrained by the uncertainties associated with the local operating, political and economic environment, including possible government interference.

Actual assigned ratings may also reflect circumstances in which the weighting of a particular factor will be different from the weighting suggested by the grid. For example, although Factors 1 and 2 address regulation and cost recovery, in some instances the effect of a company's financial strength and liquidity in Factor 4 will be given greater consideration in an assigned rating than what is indicated by the weighting in the grid.

Conclusion: Summary of the Grid-Indicated Rating Outcomes

For the 30 representative utilities highlighted, the methodology grid-indicated ratings map to current assigned ratings as follows (see Appendix B for the details):

- 30% or 9 companies map to their assigned rating
- 50% or 15 companies have grid-indicated ratings that are within one alpha-numeric notch of their assigned rating
- 20% or 6 companies have grid-indicated ratings that are within two alpha-numeric notches of their assigned rating

Grid-Indicated Rating Outcomes

Map to Assigned Rating	Map to Within One Notch	Map to Within Two Notches
American Electric Power Company, Inc.	Cemig Distribuicao S.A.	Duke Energy Corporation
Arizona Public Service Company	Consolidated Edison Company of New York	Eesti Energia AS
CLP Holdings Limited	Dominion Resources, Inc.	Eskom Holdings Ltd
Consumers Energy Company	EDP - Energias do Brasil S.A.	Korea Electric Power Corporation
Florida Power & Light Company	Emera Incorporated	Northern Illinois Gas Company
PG&E Corporation	The Empire District Electric Company	Tokyo Electric Power Company
Piedmont Natural Gas Company, Inc.	FirstEnergy Corp.	
The Southern Company	Indianapolis Power & Light Company	
Xcel Energy Inc.	Kyushu Electric Power Company	
	Oklahoma Gas and Electric Co.	
	PECO Energy Company	
	Progress Energy Carolinas, Inc.	
	Southern California Edison Company	
	Westar Energy, Inc.	
	Wisconsin Power and Light Company	

Appendix A: Regulated Electric and Gas Utilities Methodology Factor Grid

Factor 1: Regulatory Framework

Weighting: 25%	Aaa	Aa	A	Baa	Ba	B	Sub-Factor Weighting
	Regulatory framework is fully developed, has a long-track record of being predictable and stable, and is highly supportive of utilities. Utility regulatory body is a highly rated sovereign or strong independent regulator with unquestioned authority over utility regulation that is national in scope.	Regulatory framework is fully developed, has been mostly predictable and stable in recent years, and is mostly supportive of utilities. Utility regulatory body is a sovereign, sovereign agency, provincial, or independent regulator with authority over most utility regulation that is national in scope.	Regulatory framework is fully developed, has above average predictability and reliability, although is sometimes less supportive of utilities. Utility regulatory body may be a state commission or national, state, provincial or independent regulator.	Regulatory framework is a) well-developed, with evidence of some inconsistency or unpredictability in the way framework has been applied, or framework is new and untested, but based on well-developed and established precedents, or b) jurisdiction has history of independent and transparent regulation in other sectors. Regulatory environment may sometimes be challenging and politically charged.	Regulatory framework is developed, but there is a high degree of inconsistency or unpredictability in the way the framework has been applied. Regulatory environment is consistently challenging and politically charged. There has been a history of difficult or less supportive regulatory decisions, or regulatory authority has been or may be challenged or eroded by political or legislative action.	Regulatory framework is less developed, is unclear, is undergoing substantial change or has a history of being unpredictable or adverse to utilities. Utility regulatory body lacks a consistent track record or appears unsupportive, uncertain, or highly unpredictable. May be high risk of nationalization or other significant government intervention in utility operations or markets.	25%

Factor 2: Ability to Recover Costs and Earn Returns

Weighting: 25%	Aaa	Aa	A	Baa	Ba	B	Sub-Factor Weighting
	Rate/tariff formula allows unquestioned full and timely cost recovery, with statutory provisions in place to preclude any possibility of challenges to rate increases or cost recovery mechanisms.	Rate/tariff formula generally allows full and timely cost recovery. Fair return on all investments. Minimal challenges by regulators to companies' cost assumptions; consistent track record of meeting efficiency tests.	Rate/tariff reviews and cost recovery outcomes are fairly predictable (with automatic fuel and purchased power recovery provisions in place where applicable), with a generally fair return on investments. Limited instances of regulatory challenges; although efficiency tests may be more challenging; limited delays to rate or tariff increases or cost recovery.	Rate/tariff reviews and cost recovery outcomes are usually predictable, although application of tariff formula may be relatively unclear or untested. Potentially greater tendency for regulatory intervention, or greater disallowance (e.g. challenging efficiency assumptions) or delaying of some costs (even where automatic fuel and purchased power recovery provisions are applicable).	Rate/tariff reviews and cost recovery outcomes are inconsistent, with some history of unfavorable regulatory decisions or unwillingness by regulators to make timely rate changes to address market volatility or higher fuel or purchased power costs. AND/OR Tariff formula may not take into account all cost components; investment are not clearly or fairly remunerated.	Difficult or highly uncertain rate and cost recovery outcomes. Regulators may engage in second-guessing of spending decisions or deny rate increases or cost recovery needed by utilities to fund ongoing operations, or high likelihood of politically motivated interference in the rate/tariff review process. AND/OR Tariff formula may not cover return on investments, only cash operating costs may be remunerated.	25%

Factor 3: Diversification

Weighting: 10%	Aaa	Aa	A	Baa	Ba	B	Sub-Factor Weighting
Market Position	A high degree of multinational/regional diversification in terms of market and/or regulatory regime.	Material operations in more than three nations or geographic regions providing diversification of market and/or regulatory regime.	Material operations in two or three states, nations, or geographic regions and exhibits some diversification of market and/or regulatory regime.	Operates in a single state, nation, or economic region with low volatility with some concentration of market and/or regulatory regime.	Operates in a limited market area with material concentration in market and/or regulatory regime.	Operates in a single market which may be an emerging market or riskier environment, with high concentration risk.	5% *
	For LDCs, extremely low reliance on industrial customers and/or exceptionally large residential and commercial customer base and well above average growth.	For LDCs, very low reliance on industrial customers and/or very large residential and commercial customer base with very high growth.	For LDCs, low reliance on industrial customers and/or high residential and commercial customer base with high growth.	For LDCs, moderate reliance on industrial customers in defensive sectors, moderate residential and customer base.	For LDCs, high reliance on industrial customers in somewhat cyclical sectors, small residential and commercial customer base.	For LDCs, very high reliance on industrial customers in cyclical sectors, very small residential and commercial customer base.	
Generation and Fuel Diversity	A high degree of diversification in terms of generation and/or fuel source, well insulated from commodity price changes, no generation concentration, or 0-20% of generation from carbon fuels.	Some diversification in terms of generation and/or fuel source, affected only minimally by commodity price changes, little generation concentration, or 20-40% of generation from carbon fuels.	May have some concentration in one particular type of generation or fuel source, although mostly diversified, modest exposure to commodity price changes, or 40-55% of generation from carbon fuels.	Some reliance on a single type of generation or fuel source, limited diversification, moderate exposure to commodity prices, or 55-70% of generation from carbon fuels.	Operates with little diversification in terms of generation and/or fuel source, high exposure to commodity price changes, or 70-85% of generation from carbon fuels.	High concentration in a single type of generation or highly reliant on a single fuel source, little diversification, may be exposed to commodity price shocks, or 85-100% of generation from carbon fuels.	5% **

**10% weight for issuers that lack generation   **0% weight for issuers that lack generation*

Factor 4: Financial Strength, Liquidity and Key Financial Metrics

Weighting: 40%	Aaa	Aa	A	Baa	Ba	B	Sub-Factor Weighting
Liquidity	Financially robust under all scenarios with no need for external funding, unquestioned access to the capital markets, and excellent liquidity.	Financially robust under virtually all scenarios with little to no need for external funding, superior access to the capital markets, and very strong liquidity.	Financially strong under most scenarios with some reliance on external funding, solid access to the capital markets, and strong liquidity.	Some reliance on external funding and liquidity is more likely to be affected by external events, good access to the capital markets, and adequate liquidity under most scenarios.	Weak liquidity with more susceptibility to external shocks or unexpected events. Significant reliance on debt funding. Bank financing may be secured and there may be limited headroom under covenants.	Very weak liquidity with limited ability to withstand external shocks or unexpected events. Must use debt to finance investments. Bank financing is normally secured and there may be a high likelihood of breaching one or more covenants.	10%
CFO pre-WC + Interest/ Interest	> 8.0x	6.0x - 8.0x	4.5x - 6.0x	2.7x - 4.5x	1.5x - 2.7x	< 1.5x	7.5%
CFO pre-WC/ Debt	> 40%	30% - 40%	22% - 30%	13% - 22%	5% - 13%	< 5%	7.5%
CFO pre-WC - Dividends/ Debt	> 35%	25% - 35%	17% - 25%	9% - 17%	0% - 9%	< 0%	7.5%
Debt/ Capitalization	< 25%	25% - 35%	35% - 45%	45% - 55%	55% - 65%	> 65%	7.5%
Debt/RAV	< 30%	30% - 45%	45% - 60%	60% - 75%	75% - 90%	> 90%	7.5%

Regulated Electric and Gas Utilities

Appendix B: Methodology Grid-Indicated Ratings

			Factor 1: Regulatory Framework	Factor 2: Returns and Cost Recovery	Factor 3: Diversification			Factor 4: Financial Strength					
Sub-Factor Weights			25%	25%		5%	5%		10%	7.5%	7.5%	7.5%	7.5%
	Current Rating/BCA	Indicated Rating	Regulatory Supportiveness	Rate Adjustment and Cost Recovery Mechanisms	Indicated Factor 3 Rating	Market Position	Fuel or Generation Diversification	Indicated Factor 4 Rating	Liquidity	3 Year Average CFO pre-WC + Interest/ Interest	3 Year Average CFO pre-WC / Debt	3 Year Average CFO pre-W/C - Dividends / Debt	3 Year Average Debt / Cap or Debt/RAV
Kyushu Electric Power Company, Incorporated	Aa2	Aa3	Aaa	Aa	Aa	A	Aaa	A	Aa	Aa	Ba	Ba	Baa
Tokyo Electric Power Company, Incorporated	Aa2	A1	Aaa	Aa	Aa	A	Aaa	Baa	Aa	A	Ba	Ba	Ba
Eesti Energia AS	A1/[8]	A3	Baa	Baa	B	B	B	Aa	Baa	Aaa	Aaa	Aaa	Aa
Florida Power & Light Company	A1	A1	A	A	Baa	Baa	Baa	Aa	A	Aa	Aa	Aa	A
Korea Electric Power Corporation	A2/[6]	Baa1	Baa	Baa	Baa	Baa	A	A	Baa	Aa	A	A	A
CLP Holdings Limited	A2	A2	A	A	A	A	A	A	A	Aa	A	Baa	A
Northern Illinois Gas Company	A2	Baa1	Baa	Baa	A	A	N/A	Baa	Baa	A	A	Baa	Baa
Oklahoma Gas and Electric Company	A2	A3	Baa	A	Baa	Baa	Baa	A	A	A	A	A	A
Wisconsin Power and Light Company	A2	A3	A	A	Baa	Baa	Baa	A	Baa	A	A	Baa	A
Consolidated Edison Company of New York	A3	Baa1	Baa	A	Baa	Baa	N/A	Baa	A	Baa	Baa	Ba	A
PECO Energy Company	A3	Baa1	Baa	Baa	Baa	Baa	N/A	A	A	A	A	Baa	Baa
Piedmont Natural Gas Company, Inc.	A3	A3	A	A	A	A	N/A	Baa	Baa	A	Baa	Baa	Baa
Progress Energy Carolinas, Inc.	A3	A2	A	A	Baa	Baa	A	A	Baa	A	A	A	Baa
Southern California Edison Company	A3	Baa1	Baa	Baa	Baa	Baa	A	A	A	A	A	A	Baa
The Southern Company	A3	A3	A	A	Baa	A	Ba	Baa	A	A	Baa	Baa	Baa
PG&E Corporation	Baa1	Baa1	Baa	Baa	A	Baa	Aa	Baa	Baa	A	A	A	Baa
Xcel Energy Inc.	Baa1	Baa1	Baa	A	A	A	A	Baa	Baa	Baa	Baa	Baa	Baa
American Electric Power Company, Inc.	Baa2	Baa2	Baa	Baa	Baa	A	Ba	Baa	Baa	Baa	Baa	Baa	Ba

Regulated Electric and Gas Utilities

			Factor 1: Regulatory Framework	Factor 2: Returns and Cost Recovery	Factor 3: Diversification			Factor 4: Financial Strength					
Sub-Factor Weights			25%	25%		5%	5%		10%	7.5%	7.5%	7.5%	7.5%
	Current Rating/BCA	Indicated Rating	Regulatory Supportiveness	Rate Adjustment and Cost Recovery Mechanisms	Indicated Factor 3 Rating	Market Position	Fuel or Generation Diversification	Indicated Factor 4 Rating	Liquidity	3 Year Average CFO pre-WC + Interest/ Interest	3 Year Average CFO pre-WC / Debt	3 Year Average CFO pre-W/C - Dividends / Debt	3 Year Average Debt / Cap or Debt/RAV
Arizona Public Service Company	Baa2	Baa2	Ba	Baa	Baa	Baa	Baa	Baa	Baa	A	Baa	Baa	Baa
Consumers Energy Company	Baa2	Baa2	Baa	Baa	Baa	Baa	Baa	Baa	Baa	Baa	Baa	Baa	Ba
Dominion Resources, Inc.	Baa2	Baa1	Baa	A	A	A	A	Baa	Baa	Baa	Baa	Ba	Baa
Duke Energy Corporation	Baa2	A3	Baa	A	Baa	A	Baa	A	Baa	A	A	Baa	A
Emera Incorporated	Baa2	Baa1	A	A	Ba	Ba	Ba	Ba	Baa	Baa	Ba	Baa	B
The Empire District Electric Company	Baa2	Baa3	Ba	Baa	Baa	Baa	Baa	Baa	Baa	Baa	Baa	Baa	Baa
Eskom Holdings Ltd	Baa2[13]	Ba1	Ba	Ba	B	Ba	B	Baa	Ba	Ba	A	A	A
Indianapolis Power & Light Company	Baa2	Baa1	Baa	A	Ba	Baa	Ba	Baa	Baa	A	A	Baa	Baa
Cemig Distribuição S.A.	Baa3	Baa2	Ba	Ba	Ba	Ba	N/A	A	Baa	Aa	Aaa	Aa	Ba
FirstEnergy Corp.	Baa3	Baa2	Baa	Baa	Baa	A	Baa	Baa	Baa	Baa	Baa	Baa	Ba
Westar Energy, Inc.	Baa3	Baa2	Baa	Baa	Ba	Baa	Ba	Baa	Baa	Baa	Baa	Baa	Baa
EDP - Energias do Brasil S.A.	Ba1	Baa3	Ba	Ba	Baa	Baa	Baa	Baa	Ba	Baa	Aa	A	A

Positive Outlier

Negative Outlier

Appendix C: Observations and Outliers for Grid Mapping

Results of Mapping Factor 1

Factor 1: Regulatory Framework

Factor Weight		25%
	Current Rating /BCA	Regulatory Supportiveness
Kyushu Electric Power Company, Incorporated	Aa2	Aaa
Tokyo Electric Power Company, Incorporated	Aa2	Aaa
Eesti Energia AS	A1/[8]	Baa
Florida Power & Light Company	A1	A
Korea Electric Power Corporation	A2/[6]	Baa
CLP Holdings Limited	A2	A
Northern Illinois Gas Company	A2	Baa
Oklahoma Gas and Electric Company	A2	Baa
Wisconsin Power and Light Company	A2	A
Consolidated Edison Company of New York	A3	Baa
PECO Energy Company	A3	Baa
Piedmont Natural Gas Company, Inc.	A3	A
Progress Energy Carolinas, Inc.	A3	A
Southern California Edison Company	A3	Baa
The Southern Company	A3	A
PG&E Corporation	Baa1	Baa
Xcel Energy Inc.	Baa1	Baa
American Electric Power Company, Inc.	Baa2	Baa
Arizona Public Service Company	Baa2	Ba
Consumers Energy Company	Baa2	Baa
Dominion Resources, Inc.	Baa2	Baa
Duke Energy Corporation	Baa2	Baa
Emera Incorporated	Baa2	A
The Empire District Electric Company	Baa2	Ba
Eskom Holdings Ltd	Baa2/[13]	Ba
Indianapolis Power & Light Company	Baa2	Baa
Cemig Distribuição S.A.	Baa3	Ba
FirstEnergy Corp.	Baa3	Baa
Westar Energy, Inc.	Baa3	Baa
EDP - Energias do Brasil S.A.	Ba1	Ba

Observations and Outliers

As a utility's regulatory framework is one of the most important drivers of ratings, there are no outliers for this factor among the 30 issuers highlighted for this methodology.

Results of Mapping Factor 2

Factor 2: Ability to Recover Costs and Earn Returns

Factor Weight		25%
	Current Rating/BCA	Rate Adjustment and Cost Recovery Mechanisms
Kyushu Electric Power Company, Incorporated	Aa2	Aa
Tokyo Electric Power Company, Incorporated	Aa2	Aa
Eesti Energia AS	A1/[8]	Baa
Florida Power & Light Company	A1	A
Korea Electric Power Corporation	A2/[6]	Baa
CLP Holdings Limited	A2	A
Northern Illinois Gas Company	A2	Baa
Oklahoma Gas and Electric Company	A2	A
Wisconsin Power and Light Company	A2	A
Consolidated Edison Company of New York	A3	A
PECO Energy Company	A3	Baa
Piedmont Natural Gas Company, Inc.	A3	A
Progress Energy Carolinas, Inc.	A3	A
Southern California Edison Company	A3	Baa
The Southern Company	A3	A
PG&E Corporation	Baa1	Baa
Xcel Energy Inc.	Baa1	A
American Electric Power Company, Inc.	Baa2	Baa
Arizona Public Service Company	Baa2	Baa
Consumers Energy Company	Baa2	Baa
Dominion Resources, Inc.	Baa2	A
Duke Energy Corporation	Baa2	A
Emera Incorporated	Baa2	A
The Empire District Electric Company	Baa2	Baa
Eskom Holdings Ltd	Baa2/[13]	Ba
Indianapolis Power & Light Company	Baa2	A
Cemig Distribuição S.A.	Baa3	Ba
FirstEnergy Corp.	Baa3	Baa
Westar Energy, Inc.	Baa3	Baa
EDP - Energias do Brasil S.A.	Ba1	Ba

Observations and Outliers

Like Factor 1, Regulatory Framework, the ability to recover costs and earn returns is also an important ratings driver for regulated utilities, and it is not surprising that there are no outliers among the 30 issuers highlighted. For this factor, most of the issuers score exactly at their current rating levels, with the remainder scoring within one notch of their actual rating.

Results of Mapping Factor 3

Factor 3: Diversification

Sub-Factor Weights			5% *	5% **
	Current Rating/BCA	Indicated Factor 3 Rating	Market Position	Generation and Fuel Diversification
Kyushu Electric Power Company, Incorporated	Aa2	Aa	A	Aaa
Tokyo Electric Power Company, Incorporated	Aa2	Aa	A	Aaa
Eesti Energia AS	A1/[8]	B	B	B
Florida Power & Light Company	A1	Baa	Baa	Baa
Korea Electric Power Corporation	A2/[6]	Baa	Baa	A
CLP Holdings Limited	A2	A	A	A
Northern Illinois Gas Company	A2	A	A	N/A
Oklahoma Gas and Electric Company	A2	Baa	Baa	Baa
Wisconsin Power and Light Company	A2	Baa	Baa	Baa
Consolidated Edison Company of New York	A3	Baa	Baa	N/A
PECO Energy Company	A3	Baa	Baa	N/A
Piedmont Natural Gas Company, Inc.	A3	A	A	N/A
Progress Energy Carolinas, Inc.	A3	Baa	Baa	A
Southern California Edison Company	A3	Baa	Baa	A
The Southern Company	A3	Baa	A	Ba
PG&E Corporation	Baa1	A	Baa	Aa
Xcel Energy Inc.	Baa1	A	A	A
American Electric Power Company, Inc.	Baa2	Baa	A	Ba
Arizona Public Service Company	Baa2	Baa	Baa	Baa
Consumers Energy Company	Baa2	Baa	Baa	Baa
Dominion Resources, Inc.	Baa2	A	A	A
Duke Energy Corporation	Baa2	Baa	A	Baa
Emera Incorporated	Baa2	Ba	Ba	Ba
The Empire District Electric Company	Baa2	Baa	Baa	Baa
Eskom Holdings Ltd	Baa2/[13]	B	Ba	B
Indianapolis Power & Light Company	Baa2	Ba	Baa	Ba
Cemig Distribuição S.A.	Baa3	Ba	Ba	N/A
FirstEnergy Corp.	Baa3	Baa	A	Baa
Westar Energy, Inc.	Baa3	Ba	Baa	Ba
EDP - Energias do Brasil S.A.	Ba1	Baa	Baa	Baa

Observations and Outliers

Of the 30 issuers highlighted, there are three outliers, including PG&E Corporation as a positive outlier, due to their high degree of generation diversification and the lack of coal in their generation mix, and both Eesti Energia AS and The Southern Company as negative outliers. As an Estonian vertically integrated dominant electric utility, Eesti Energia is exposed to considerably high concentration risk as it operates in one of the smallest CEE emerging markets. The concentration risk is further worsened by the company's high reliance on one fuel source as its generation is fully based on internationally rare oil shale. Furthermore, as the oil shale generation is relatively CO2 intensive, Eesti Energia is further exposed to the development of CO2 allowance prices. The Southern Company is one of the largest coal generating utility systems in the U.S., with a high percentage of its generation from carbon fuels.

Results of Mapping Factor 4

Factor 4: Financial Strength, Liquidity and Key Financial Metrics

Sub-Factor Weights			10%	7.5%	7.5%	7.5%	7.5%
	Current Rating/BCA	Indicated Factor 4 Rating	Liquidity	3 Year Average CFO pre-WC + Interest/ Interest	3 Year Average CFO pre-WC / Debt	3 Year Average CFO pre-WC / Debt	3 Year Average Debt / Cap or Debt/RAV
Kyushu Electric Power Company, Incorporated	Aa2	A	Aa	Aa	Ba	Ba	Baa*
Tokyo Electric Power Company, Incorporated	Aa2	Baa	Aa	A	Ba	Ba	Ba*
Eesti Energia AS	A1/[8]	Aa	Baa	Aaa	Aaa	Aaa	Aa
Florida Power & Light Company	A1	Aa	A	Aa	Aa	Aa	A
Korea Electric Power Corporation	A2/[6]	A	Baa	Aa	A	A	A
CLP Holdings Limited	A2	A	A	Aa	A	Baa	A
Northern Illinois Gas Company	A2	Baa	Baa	A	A	Baa	Baa
Oklahoma Gas and Electric Company	A2	A	A	A	A	A	A
Wisconsin Power and Light Company	A2	A	Baa	A	A	Baa	A
Consolidated Edison Company of New York	A3	Baa	A	Baa	Baa	Ba	A
PECO Energy Company	A3	A	A	A	A	Baa	Baa
Piedmont Natural Gas Company, Inc.	A3	Baa	Baa	A	Baa	Baa	Baa
Progress Energy Carolinas, Inc.	A3	A	Baa	A	A	A	Baa
Southern California Edison Company	A3	A	A	A	A	A	Baa
The Southern Company	A3	Baa	A	A	Baa	Baa	Baa
PG&E Corporation	Baa1	Baa	Baa	A	A	A	Baa
Xcel Energy Inc.	Baa1	Baa	Baa	Baa	Baa	Baa	Baa
American Electric Power Company, Inc.	Baa2	Baa	Baa	Baa	Baa	Baa	Ba
Arizona Public Service Company	Baa2	Baa	Baa	A	Baa	Baa	Baa
Consumers Energy Company	Baa2	Baa	Baa	Baa	Baa	Baa	Ba
Dominion Resources, Inc.	Baa2	Baa	Baa	Baa	Baa	Ba	Baa
Duke Energy Corporation	Baa2	A	Baa	A	A	Baa	A
Emera Incorporated	Baa2	Ba	Baa	Baa	Ba	Baa	B
The Empire District Electric Company	Baa2	Baa	Baa	Baa	Baa	Baa	Baa
Eskom Holdings Ltd	Baa2/[13]	Baa	Ba	Ba	A	A	A
Indianapolis Power & Light Company	Baa2	Baa	Baa	A	A	Baa	Baa
Cemig Distribuição S.A.	Baa3	A	Baa	Aa	Aaa	Aa	Ba
FirstEnergy Corp.	Baa3	Baa	Baa	Baa	Baa	Baa	Ba
Westar Energy, Inc.	Baa3	Baa	Baa	Baa	Baa	Baa	Baa
EDP - Energias do Brasil S.A.	Ba1	Baa	Ba	Baa	Aa	A	A

*Debt/RAV

Positive Outlier
Negative Outlier

Observations and Outliers

This factor takes into account historic financial statements. Historic results help us to understand the pattern of a utility's financial and operating performance and how a utility compares to its peers. While Moody's rating committees and the rating process use both historical and projected financial results, this document makes use only of historic data, and does so solely for illustrative purposes.

While the vast majority of utilities' key financial metrics map fairly closely to their ratings, there are several significant outliers, which generally fall into two broad groups. The first group is composed of negative outliers and include several utilities located in stable and supportive regulatory environments and are characterized by very low business risk. In these cases, the utilities may have lower financial ratios and higher leverage than most peer companies on a global basis, but still maintain higher overall ratings. In short, the certainty provided by regulatory stability and low business risk offsets any risks that may result from lower financial ratios. Examples of such negative outliers on the financial strength factor include most of the major Japanese utilities, including Tokyo Electric Power and Kyushu Electric Power.

The second group of outliers is composed of positive outliers, whereby several financial ratios are stronger than the overall Moody's rating. These include several utilities in Latin America, such as Cemig Distribuicao, EDP-Energias do Brasil, and European Eesti Energia, which exhibit strong financial coverage ratios and low debt levels, but where ratings are constrained by a more difficult regulatory or business environment or a sovereign rating ceiling.

Appendix D: Definition of Ratios

Cash Flow Interest Coverage

(Cash Flow from Operations – Changes in Working Capital + Interest Expense) / (Interest Expense + Capitalized Interest Expense)

CFO pre-WC / Debt

(Cash Flow from Operations – Changes in Working Capital) / (Total debt + operating lease adjustment + under-funded pension liabilities + basket-adjusted hybrids + securitizations + guarantees + other debt-like items)

CFO pre-WC - Dividends / Debt

(Cash Flow from Operations – Changes in Working Capital – Common and Preferred Dividends) / (Total debt + operating lease adjustment + under-funded pension liabilities + basket-adjusted hybrids + securitizations + guarantees + other debt-like items)

Debt / Capitalization or Regulated Asset Value

(Total debt + operating lease adjustment + under-funded pension liabilities + basket-adjusted hybrids + securitizations + guarantees + other debt-like items) / (Shareholders' equity + minority interest + deferred taxes + goodwill write-off reserve + Total debt + operating lease adjustment + under-funded pension liabilities + basket-adjusted hybrids + securitizations + guarantees + other debt-like items) or RAV

Appendix E: Industry Overview

The electric and gas utility industry consists of companies that are engaged in the generation, transmission, and distribution of electricity and/or natural gas. While many utilities remain vertically integrated with operations in all three segments, others have functionally or legally unbundled these functions due to legislatively mandated market restructuring or other deregulation initiatives and may be engaged in just one or two of these activities.

The **generation** of electricity is the first step in the process of producing and delivering electricity to end use customers and typically the most capital intensive, with the largest portion of the industry's assets consisting of generating plants and related hard assets. Electricity is generated from a variety of fuel sources, including coal, natural gas, or oil; nuclear energy; and renewable sources such as hydro, wind, solar, geothermal, wood, and waste.

Transmission is the high voltage transfer of electricity over long distances from its source, usually the location of a generating plant, to substations closer to end use customers in population or industrial centers. Although many utilities own and operate their own transmission systems, there are also several independent transmission companies included in this methodology.

The **distribution** of electricity is the process whereby voltage is reduced and delivered from a high voltage transmission system through smaller wires to the end-users, which consist of industrial, commercial, government, or retail customers of the utility. Most of the utilities covered by this methodology are engaged to some degree in the distribution of electricity through "poles and wires" to their end customers. The distribution of natural gas entails the transport of gas from delivery points along major pipelines to customers in their service territory through distribution pipes.

Regulation Plays a Major Role in the Industry

Because of the essential nature of the utility's end products (electricity and gas), the public policy implications associated with their provision, the demands for high levels of reliability in their delivery, the monopoly status of most service territories, and the high capital costs associated with its infrastructure, the utility industry is generally subject to a high degree of government regulation and oversight. This regulation can take many forms and may include setting or approving the rates or other cost recovery mechanisms that utilities charge for their services (revenue), determining what costs can be recovered through base rates, authorizing returns that utilities earn on their investments, defining service territories, mandating the level and reliability of electricity and gas service that must be provided and enforcing safety standards. From a credit standpoint, the regulators' ability to set and control rates and returns is perhaps the most important regulatory consideration in determining a rating.

In the U.S., the most important utility regulator for most companies is the individual state agency generally known as the Public Utility Commission or the Public Service Commission. The commissions are comprised of elected or appointed officials in each state who determine, among other things, whether utility expenditures are reasonable and/or prudent and how they should be passed on to consumers through their utility rates. While some states have legislatively mandated certain market restructuring or deregulation initiatives with regard to the generation segment of their electricity markets, the majority of states remain fully regulated, and some states that had deregulated are in the process of "re-regulating" their electricity markets.

The key federal agency governing utilities in the U.S. is the Federal Energy Regulatory Commission (FERC), an independent agency that regulates, among other things, the interstate transmission of electricity and natural gas. The FERC's responsibilities include the approval of rates for the wholesale sale and transmission of electricity on an interstate basis by utilities, power marketers, power pools, power exchanges, and independent system operators. The Energy Policy Act of 2005 increased the FERC's regulatory authority in a wide range of areas including mergers and acquisitions, transmission siting, market practices, price transparency, and regional transmission organizations.

Regulated Electric and Gas Utilities

In Europe, following the implementation of specific policies relating to the liberalization of energy supply within the European Union (EU), the electric utility sector has been evolving toward a model targeting complete separation between network activities, regulated in light of their monopoly nature, and supply and production of energy, fully liberalized and hence unregulated. As a result of this process, most Western European utilities currently operate either as fully regulated entities in the networks segment, or largely unregulated integrated companies (albeit some may still maintain some regulated network activity), and are therefore excluded from the scope of this methodology. Nevertheless, there are countries in Europe where regulatory evolution and transition to competition remain at an earlier stage (Central and Eastern European countries and the Baltic states in particular) and/or are characterized by the remoteness and isolation of their systems (the islands in the Azores and Madeira regions for example). In these countries, Governments and/or Regulators maintain greater influence on the bulk of the utilities' revenues, thus supporting their inclusion in this methodology.

In Japan, regulation has been an important positive factor supporting utility credit quality. Japan's regulator makes the maintenance of supply its primary policy objective, followed in priority by environmental protection and finally, allowing market conditions to work. This approach preserves the utilities' integrated operations and makes them responsible for final supply to users in the liberalized market. The Japanese government is gradually deregulating the utility industry and expanding the liberalized market. However, the pace of deregulation has been moderate so that the regulator can monitor the risks and the effects on the power companies, especially in the context of generation supply security.

In Australia, stable and predictable regulatory regimes continue to underpin the investment-grade characteristics of the sector. So far, regulators – which operate independently from the governments – have not adopted an aggressive stance to revenues and returns as they seek a balance between: appropriate returns for utilities; ongoing incentives for network investments; and appropriate prices for consumers. The supportiveness of the regimes will become increasingly important over the medium term as the sector undertakes investments to expand network capacity and replace ageing assets to meet rising demand.

In Asia Pacific (ex-Japan), regulation of electric utilities is overseen by government regulatory bodies in their respective countries. As such, the stability and regulatory framework can vary to a large extent by country with a few utilizing automatic cost pass through mechanisms while the majority operate with ad hoc tariff adjustments. However, power security remains a key policy objective and regulators continue to seek to ensure stability in regulatory and operating environments. Such regulatory environments are critical to attracting investments for both privatizations and for funding expanding electricity projects. Reform of the power industry in Asia remains slow paced and competition is well contained. Regulators have shown that they will reform in a prudent manner and allow tariff adjustment to minimize any material negative impact on the credit profiles of their power utilities. Such a supportive approach enhances stability and provides a stable regulatory regime which in turn remains a key driver in supporting the cash flows of Asia Pacific (ex-Japan) utilities.

In Canada, regulation of electric and gas utilities is overseen by independent, quasi-judicial provincial or territorial regulatory bodies. Accordingly, the transparency and stability of regulation and the timeliness of regulatory decisions can vary by jurisdiction. However, generally the regulatory frameworks in each jurisdiction are well established and there is a high expectation of timely recovery of cost and investments. Furthermore, Moody's considers the overall business environment in Canada to be relatively more supportive and less litigious than that of the U.S. Moody's views the supportiveness of the Canadian business and regulatory environments to be positive for regulated utility credit quality and believes that these factors, to some degree, offset the relatively lower ROEs and higher deemed debt components typically allowed by Canadian regulatory bodies for rate-making purposes. As a result of the relatively low ROEs and higher deemed debt levels that are generally characteristic of Canadian utilities, for a given rating category, these entities often have weaker credit metrics than their international peers.

In Latin America, there is a perceived lower level of regulatory supportiveness than in other regions. In Argentina, although the generation industry is deregulated, the government continues to intervene in the process of setting prices and tariffs. In addition, collections from sales to the spot market have only been partial and have depended on the government's discretion. Moody's views the current regulatory framework as a relatively high risk factor given the government's interference, the unclear regulations, the lack of support for the companies' profitability, and the lack of incentives for much needed long-term investment. Brazil's power generation companies could also be affected by unfavorable regulatory decisions, since about 75% of its electricity currently goes to the regulated market, but Moody's last year noted improvements in Brazil's regulatory environment, which led to several issuer upgrades. Brazil's regulatory model provides a more supportive environment for acceptable rates of return since the current rules for electric utilities are more transparent and technically driven. Nonetheless, there is a lower assurance of timely recovery of costs and investments in Brazil since the new framework has not yet experienced the stress of high inflation, exchange rate devaluation or electricity rationing. Recent distribution tariff review reductions have typically been in the high-single-digit range, which is considered modest, particularly compared to Moody's rated issuers in El Salvador (14% reduction) and Guatemala (45% reduction) both of which led to downgrades last year. The regulatory framework in Chile, in Moody's opinion, comes closest to the United States in terms of regulatory supportiveness.

Appendix F: Key Rating Issues Over the Intermediate Term

Global Climate Change and Environmental Awareness

Electric and gas utilities will continue to be affected by growing concerns over global climate change and greenhouse gas emissions, which are particularly important in the electricity generation segment which continues to rely on a large number of coal and natural gas fired power plants. There have been significant increases in environmental expenditure estimates among utilities with significant coal fired generation in recent years as policymakers have mandated pollution control measures and emissions limitations in response to public concerns over carbon. These expenditures are likely to continue to increase with the imposition of new and sometimes uncertain requirements with respect to carbon emissions. Utilities may have to implement substantial additional reductions in power plant emissions and could experience progressively higher capital expenditures over the next decade. In the U.S., the planned construction of several new coal plants has been cancelled as a result of opposition from regulators, political leaders, and the public or because cheaper alternatives appeared more compelling due to higher coal plant construction costs.

Large Capital Expenditures and Rising Costs for New Generation and Transmission

While the global recession may have reduced electric demand in certain regions in the short-term, longer-term worldwide demand for electricity is expected to continue to grow and many utilities will incur substantial capital expenditures for new generation, as well as for upgrades and expansions to transmission systems. In the U.S., the Edison Electric Institute projects annual capacity additions among investor-owned utilities to increase to over 15,000 megawatts (MW) in 2009 compared with less than 6,000 MW in 2006. Some of the new plants announced include large, highly capital intensive nuclear plants, which have not been built in the U.S. in many years. In Indonesia, the Fast Track program calls for the addition of 9,000 MW of coal-fired power plants while India plans to build eight ultra-mega power projects (each under 4,000 MW). Similar large nuclear plants are being constructed worldwide in countries as diverse as Bulgaria, China, India, Russia, South Korea, Taiwan and Ukraine. Because of this construction boom, international demand for certain construction materials, plant components and skilled labor has driven up the cost of new nuclear. More recently, the global economic slowdown may relieve some of this cost pressure.

Political and Regulatory Risk

As the utility industry faces higher operating costs, rising environmental compliance expenditures, large capital expenditures for new generation, as well as fuel and commodity price risks, the need for rate relief and other regulatory support will continue to be a key rating factor. In the U.S., political intervention in the regulatory process following particularly large rate increase requests increased risk and negatively affected the credit ratings of utilities in Illinois and Maryland in recent years. In Europe, rising electricity prices two years ago resulted in widespread criticism of utilities in several countries, increasing regulatory and political risk for some of them. In Australia, the transition from state based regulation to a national regulatory framework could pose a moderate level of uncertainty to current regulatory thinking over the longer term. In Asia Pacific (ex-Japan) and Latin America, the governments face political pressure regarding tariff adjustments given their need to balance socio-economic targets and inflationary concerns against the objective of ensuring reliable electricity supply over the long term.

Economic and Financial Market Conditions

Although electric and gas utilities are somewhat resistant (although not immune) to unsettled economic and financial market conditions due partly to the essential nature of the service provided, a protracted or severe recession could negatively affect credit profiles over the intermediate term in several ways. Falling demand for electricity or natural gas could negatively impact margins and debt service protection measures. Poor economic conditions could make it more difficult for regulators to approve needed rate increases or provide timely cost recovery for utilities, resulting in higher cost deferrals and longer regulatory lag. Finally, *constrained capital market conditions could* severely limit the availability of credit necessary to finance needed capital expenditures, or make such financing plans more expensive.

Appendix G: Regional and Other Considerations

Notching Considerations - Structural Subordination and Holding Company Ratings

Utility corporate structures often include multiple legal entities within a single consolidated organization under an unregulated parent holding company. The holding company typically has one or more regulated operating subsidiaries and may have one or more unregulated subsidiaries as well. Most utility families issue debt at several of these legal entities within the organizational family including the parent holding company and the utility subsidiaries. In such cases, our approach is to assess each issuer on a standalone basis as well as to evaluate the creditworthiness of the consolidated entity. We also consider the interdependent relationships that may exist among affiliates and the degree to which a management team operates its utility subsidiaries as a system. We then assess the degree of legal and regulatory insulation that exists between the generally lower-risk regulated entities and the generally higher-risk unregulated entities.

The *degree of notching* (or *rating differential*) between entities in a single family of companies depends on the degree of insulation that exists between the regulated and unregulated entities, as well as the amount of debt at the holding company in comparison to the consolidated entity. If there is minimal insulation or ring-fencing between the parent and subsidiary and little to no debt at the parent, there is typically a one notch differential between the two to reflect structural subordination of the parent company debt compared to the operating subsidiary debt. If there is substantial insulation between the two and/or debt at the parent company is a material percentage of the overall debt, there could be two or more notches between the ratings of the parent and the subsidiary.

U.S. Securitization

Since the late 1990s, legislatively approved stranded cost and other regulatory asset securitization has become an increasingly utilized financing technique among some investor-owned electric utilities. In its simplest form, a stranded cost securitization isolates and dedicates a stream of cash flow into a separate special purpose entity (SPE). The SPE uses that stream of revenue and cash flow to provide annual debt service for the securitized debt instrument. Securitizations were originally done to reimburse utilities for stranded costs following deregulation, which was primarily related to the actual lower market values of the legacy generation compared to its book value. More recently, securitizations have been done to reimburse utilities for storm restoration costs following two active hurricane seasons in the U.S. in 2004 and 2005, with additional securitizations planned following an active 2008 hurricane season, as well as for environmental equipment. In 2007, Baltimore Gas & Electric used securitization to fund supply cost deferrals. Securitization could also be used to help fund the next generation of nuclear plants to be built in the U.S.

Although it often addresses a major credit overhang and provides an immediate source of cash, Moody's treats securitization debt of utilities as being on-credit debt. In calculating balance sheet leverage, Moody's treats the securitization as being fully recourse to the utility as accounting guidelines require the debt to appear on the utility's balance sheet. In looking at cash flow coverages, Moody's analysis focuses on ratios that include the securitized debt in the company's total debt as being the most consistent with the analysis of comparable companies. Securitizations also entail transition or other charges on ratepayer bills that may limit a utility's flexibility to raise rates for other reasons going forward. While our standard published credit ratios include the securitization debt, we also look at the ratios without the securitization debt and cash flow in our analysis, to distinguish this debt and ensure that the benefits of securitization are not ignored.

Strong levels of government ownership in Asia Pacific (ex-Japan) provide rating uplift

Strong levels of government ownership dominate Asia Pacific (ex-Japan) power utilities and remain one of their key rating drivers. The current majority state ownership levels are expected to remain largely unchanged for the near to medium term, thereby providing rating uplift to a majority of the government-owned Asia Pacific (ex-Japan) utilities under the Joint Default Analysis methodology.

Appendix H: Treatment of Power Purchase Agreements ("PPA's")

Although many utilities own and operate power stations, some have entered into PPAs to source electricity from third parties to satisfy retail demand. The motivation for these PPAs may be one or more of the following: to outsource operating risks to parties more skilled in power station operation, to provide certainty of supply, to reduce balance sheet debt, or to fix the cost of power. While Moody's regards these risk reduction measures positively, some aspects of PPAs may negatively affect the credit of utilities.

Under most PPAs, a utility is obliged to pay a capacity charge to the power station owner (which may be another utility or an Independent Power Producer – IPP); this charge typically covers a portion of the IPP's fixed costs in relation to the power available to the utility. These fixed payments usually help to cover debt service and are made irrespective of whether the utility requires the IPP to generate and deliver power. When the utility requires generation, a further energy charge, to cover the variable costs of the IPP, will also be paid by the utility. Some other similar arrangements are characterized as tolling agreements, or long-term supply contracts, but most have similar features to PPAs and are thus analyzed by Moody's as PPAs.[4]

Factors determining the treatment of PPAs

Because PPAs have a wide variety of financial and regulatory characteristics, each particular circumstance may be treated differently by Moody's. The most conservative treatment would be to treat the PPA as a debt obligation of the utility as, by paying the capacity charge, the utility is effectively providing the funds to service the debt associated with the power station. At the other end of the continuum, the financial obligations of the utility could also be regarded as an ongoing operating cost, with no long-term capital component recognized. Factors which determine where on the continuum Moody's treats a particular PPA are as follows:

- Risk management: An overarching principle is that PPAs have been used by utilities as a risk management tool and Moody's recognizes that this is the fundamental reason for their existence. Thus, Moody's will not automatically penalize utilities for entering into contracts for the purpose of reducing risk associated with power price and availability. Rather, we will look at the aggregate commercial position, evaluating the risk to a utility's purchase and supply obligations. In addition, PPAs are similar to other long-term supply contracts used by other industries and their treatment should not therefore be fundamentally different from that of other contracts of a similar nature.
- Pass-through capability: Some utilities have the ability to pass through the cost of purchasing power under PPAs to their customers. As a result, the utility takes no risk that the cost of power is greater than the retail price it will receive. Accordingly Moody's regards these PPA obligations as operating costs with no long-term debt-like attributes. PPAs with no pass-through ability have a greater risk profile for utilities. In some markets, the ability to pass through costs of a PPA is enshrined in the regulatory framework, and in others can be dictated by market dynamics. As a market becomes more competitive, the ability to pass through costs may decrease and, as circumstances change, Moody's treatment of PPA obligations will alter accordingly.
- Price considerations: The price of power paid by a utility under a PPA can be substantially below the current spot price of electricity. This will motivate the utility to purchase power from the IPP even if it

[4] When take-or-pay contracts, outsourcing agreements, PPAs and other rights to capacity are accounted for as leases under US GAAP or IFRS, they are treated by Moody's as such for analytical purposes.

does not require it for its own customers, and to sell excess electricity in the spot market. This can be a significant source of cash flow for some utilities. On the other hand, utilities that are compelled to pay capacity payments to IPPs when they have no demand for the power or when the spot price is lower than the PPA price will suffer a financial burden. Moody's will particularly focus on PPAs that have mark-to-market losses that may have a material impact on the utility's cash flow.

- Excess Reserve Capacity: In some jurisdictions there is substantial reserve capacity and thus a significant probability that the electricity available to a utility under PPAs will not be required by the market. This increases the risk to the utility that capacity payments will need to be made when there is no demand for the power. For example, Tenaga, the major Malaysian utility, purchases a large proportion of its power requirement from IPPs under PPAs. PPA payment totaled 42.0% of its operating costs in FY2008. In a high reserve margin environment existing in Malaysia, capacity payment under these PPAs are a significant burden on Tenaga, and some account must be made for these payments in its financial metrics.
- Risk-sharing: Utilities that own power plants bear the associated operational, fuel procurement and other risks. These must be balanced against the financial and liquidity risk of contracting for the purchase of power under a PPA. Moody's will examine on a case-by case basis which of these two sets of risk poses greatest concern from a ratings standpoint.
- Default provisions: In most cases, a default under a PPA will not cross-default to the senior facilities of the utility and thus it is inappropriate to add the debt amount of the PPA to senior debt of the entity. The PPA obligations are not senior obligations of the utility as they do not behave in the same way as senior debt. However, it may be appropriate in some circumstances to add the PPA obligation to Moody's debt, in the same way as other off-balance sheet items.[5]
- Accounting: From a financial reporting standpoint, very few PPA's have thus far resulted in IPP's being consolidated by the off taker. Similarly, very few PPA's are treated as lease obligations. Due to upcoming accounting rule changes[6], however, coupled with many contracts being renegotiated and extended over the next several years, we expect to see an increasing number of projects being consolidated or PPA's accounted for as leases on utility financial statements. Many of the factors assessed in the accounting decision are the same as in our analysis, i.e. risk and control. However, our analysis also considers additional factors that the accountants may not, such as the ability to pass through costs. We will consider the rationale behind the accounting decision and compare it to our own analysis and may not necessarily come to the same conclusion as the accountants.

Each of these factors will be weighed by Moody's analysts and a decision will be made as to the importance of the PPA to the risk analysis of the utility.

Methods of accounting for PPAs in our analysis

According to the weighting and importance of the PPA to each utility and the level of disclosure, Moody's may analytically assess the total debt obligations for the utility using one of the methods discussed below.

- Operating Cost: If a utility enters into a PPA for the purpose of providing an assured supply and there is reasonable assurance that regulators will allow the costs to be recovered in regulated rates, Moody's may view the PPA as being most akin to an operating cost. In this circumstance, there most likely will be no imputed adjustment to the debt obligations of the utility. In the event operating costs are consolidated, we will attempt to deconsolidate these costs from a utility's financial statements.
- Annual Obligation x 6: In some situations, the PPA obligation may be estimated by multiplying the annual payments by a factor of six (in most cases). This method is sometimes used in the capitalization of operating leases. This method may be used as an approximation where the analyst determines that the obligation is significant but cannot be quantified otherwise due to limited information.

[5] See "The Analysis of Off-Balance Sheet Exposures – A Global Perspective", Rating Methodology, July 2004.
[6] SFAS 167 "Amendments to FASB Interpretation No. 46(r)" will be effective Q1 2010.

- Net Present Value: Where the analyst has sufficient information, Moody's may add the NPV of the stream of PPA payments to the debt obligations of the utility. The discount rate used will be the cost of capital of the utility.
- Debt Look-Through: In some circumstances, where the debt incurred by the IPP is directly related to the off-taking utility, there may be reason to allocate the entire debt (or a proportional part related to share of power dedicated to the utility) of the IPP to that of the utility.
- Mark-to-Market: In situations in which Moody's believes that the PPA prices exceed the spot price and thus a liability is arising for the utility, Moody's may use a net mark-to-market method, in which the NPV of the net cost to the utility will be added to its total debt obligations.
- Consolidation: In some instances where the IPP is wholly dedicated to the utility, it may be appropriate to consolidate the debt and cash flows of the IPP with that of the utility. Again, if the utility purchases only a portion of the power from the IPP, then that proportion of debt might be consolidated with the utility.

In some circumstances, Moody's will adopt more than one method to estimate the potential obligations imposed by the PPA. This approach recognizes the subjective nature of analyzing agreements that can extend over a long period of time and can have a different credit impact when regulatory or market conditions change. In all methods the Moody's analyst will account for the revenue from the sale of power bought from the IPP. We will focus on the term to maturity of the PPA obligation, the ability to pass through costs and curtail payments, and the materiality of the PPA obligation to the overall cash flows of the utility in assessing the effect of the PPA on the credit of the utility.

Moody's Related Research

Industry Outlooks:

- U.S. Regulated Electric Utilities, Six-Month Update, July 2009 (118776)
- U.S. Investor-Owned Electric Utility Sector, January 2009 (113690)
- EMEA Electric and Gas Utilities, November 2008 (112344)
- North American Natural Gas Transmission & Distribution, March 2009 (115150)

Rating Methodologies:

- Unregulated Utilities and Power Companies, August 2009 (118508)
- Regulated Electric and Gas Networks, August 2009 (118786)

Special Comments:

- Credit Roadmap for Energy Utilities and Power Companies in the Americas, March 2009 (115514)

To access any of these reports, click on the entry above. Note that these references are current as of the date of publication of this report and that more recent reports may be available. All research may not be available to all clients.

Regulated Electric and Gas Utilities

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KENTUCKY UTILITIES COMPANY

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Question No. 2

Witness: Shannon L. Charnas / Robert M. Conroy

Q-2. Refer to pages 15-18 of the Bellar Testimony, which indicate KU is seeking recovery of beneficial reuse opportunities through its Environmental Cost Recovery ("ECR") mechanism. Provide a schedule with account name and amounts of KU's beneficial reuse expenses for calendar years 2005 through 2008 and year-to-date for 2009.

A-2. Attached is detail regarding beneficial reuse costs and income for 2005 through July 31, 2009. As beneficial reuse projects are identified and related costs or income are recorded, KU will continually review these in comparison to those O&M expenses that are already included in base rates and recognize any impact in the surcharge calculations consistent with the Commission's orders.

Assuming Commission approval of Project No. 33 for recovery through the ECR, for the generating facilities for which beneficial reuse projects are included in the ECR KU will net the amount included in the ECR with those beneficial reuse expenses and revenues included in existing base rates at those same generating facilities. In its next base rate case, KU will make a pro forma adjustment to remove beneficial reuse expenses and revenues for those generating facilities for which beneficial reuse projects are included in the ECR from its revenue requirement calculations. Going forward after approval of base rates 100% of beneficial reuse expenses and revenues for those generating facilities will be included in the ECR filings.

Kentucky Utilities
Beneficial Reuse Expenses

	2005	2006	2007	2008	Jan - Jul 2009	Credits relate to:
Ghent						
502001 OTHER WASTE DISPOSAL	$ (846,365)	$ (799,245)	$ (559,389)	$ (699,719)	$ (257,874)	Gypsum sales
Total Ghent	$ (846,365)	$ (799,245)	$ (559,389)	$ (699,719)	$ (257,874)	
Tyrone						
501251 FLY ASH DISPOSAL	$ -	$ -	$ 470,029	$ 459,751	$ -	
Total Tyrone	$ -	$ -	$ 470,029	$ 459,751	$ -	

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Question No. 3

Witness: Lonnie E. Bellar

Q-3. Refer to page 18 of the Bellar Testimony.

a. Explain if this is the section of the testimony to which Mr. Voyles refers on pages 39 of his testimony which reads, "As stated in Mr. Bellar's testimony, KU is seeking authorization to pursue and proceed with beneficial reuse opportunities without being subject to amending the Company's Compliance Plan."

b. Mr. Bellar states that "KU proposes to include the current monthly costs associated with such a beneficial reuse opportunity in its ECR filing forms." Assuming the beneficial reuse proposal is approved, would KU be agreeable to including a narrative description of the specific reuse opportunity with the first monthly ECR filing that includes the costs thereof?

A-3. a. Yes, page 39 of Mr. Voyles' testimony refers to page 18 of Mr. Bellar's testimony. KU is requesting Commission approval for ECR cost recovery for the costs associated with beneficial reuse opportunities determined to be cost-effective through the evaluation methods described in the testimony of Mr. Schram. The approval of ECR cost recovery for beneficial reuse opportunities provides KU the necessary authority to make appropriate business decisions involving reasonable, cost-effective beneficial reuse opportunities, subject to ongoing oversight and scrutiny of the Commission. The Commission also has six-month and two-year reviews for further oversight and review of the cost-effectiveness of each beneficial reuse project included in the monthly filings

b. Yes. KU will provide a narrative description of each beneficial reuse opportunity that includes associated costs that are recoverable through the environmental surcharge with the first monthly ECR filing that includes those costs. As stated in Mr. Conroy's testimony, page 5, for the beneficial reuse opportunities that KU determines to be cost effective and that should be pursued and recovered through the ECR mechanism, the evaluation results will be provided to the Commission as an attachment to the monthly filing in the first month the beneficial reuse costs are reported.

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Question No. 4

Witness: John N. Voyles, Jr.

Q-4. Refer to pages 22--23 of the Direct Testimony of John N. Voyles, Jr. ("Voyles Testimony") regarding the Brown Station Ash Treatment Basin Expansion (Project 29).

a. On pages 22-23, Mr. Voyles refers to increasing the elevation of the auxiliary pond to 900 feet, an elevation at which it "is projected to contain sufficient capacity for bottom ash storage for approximately 30 years." Does KU believe it needs such capacity for 30 years at the Brown Station? Explain the response.

b. On page 23, Mr. Voyles discusses the reports prepared by Fuller, Mossbarger, Scott, and May ("FMSM''). Describe, generally, the process under which FMSM was selected to perform the analysis of the storage needs at Brown.

A-4. a. Yes. The Brown station is a base-load generating station required to meet the needs of customers. The Auxiliary Pond was initially constructed to 880' and will be used to store all CCP from the station while the main pond's initial phases are being constructed. This temporary use of the auxiliary pond will use the majority of the constructed capacity. The auxiliary pond is now being elevated to 900' and will be used for long term bottom ash storage only. Based on 2005 CCP production data for bottom ash, the original design life of the Auxiliary Pond was 20 years; changes in actual CCP production rates cause the projected life to vary and the projection is now 30 years, for bottom ash storage only. If the auxiliary pond were to be used for all ash storage, then the projected design life would be less than three years.

The incremental increase in elevation from 880' to 900' is, in the Company's best engineering judgment, the increase that maximizes the value of the proposed construction expense being incurred and minimizes overall costs to its customers. Additionally, the design for the Auxiliary Pond will use the gypsum produced by the FGD currently under construction as fill material in the increased impoundment elevation. If the Auxiliary Pond were being elevated to a lower height than is planned, KU would have to utilize some of the capacity of the auxiliary pond to store the gypsum not used in the auxiliary pond extension, thereby reducing the projected life of the pond.

Further, KU is utilizing the phased approach to construction of the main pond expansion in order to enhance its ability to flexibly respond to unanticipated circumstances. Should the expected utilization of the Brown station change significantly, planned increases in the vertical elevation of the main pond could be optimized or eliminated and the ash/gypsum transfer system modified to use remaining capacity in both the main pond, or in the event of a station shutdown, the auxiliary pond

b. The analysis of the storage needs at E.W. Brown was competitively bid to local and national Civil and Geotechnical Engineering firms with experience in developing CCP storage facilities in 2005. Companies included in the competitive RFP process were MACTEC, Burns & McDonnell, and Stantec (formerly FMSM). See also the response to Question No. 24.

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Question No. 5

Witness: John N. Voyles, Jr.

Q-5. Refer to pages 23--27 of the Voyles Testimony regarding the Ghent Station landfill (Project 30). On page 26, Mr. Voyles discusses two reports prepared by GAI Consultants ("GAI") on the siting and design of Project 30. Describe, generally, the process under which GAI was selected to perform this work.

A-5. The analysis of the storage needs at Ghent was competitively bid to local Civil and Geotechnical Engineering firms with experience in developing CCP storage facilities in 2008. Companies included in the competitive RFP process were MACTEC, ATC, GAI and Stantec (formerly FMSM). See also the response to Question No. 24.

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Question No. 6

Witness: John N. Voyles, Jr.

Q-6. Refer to pages 27-31 of the Voyles Testimony regarding the Trimble County ash treatment basin/gypsum storage pond (Project 31).

a. On page 29, Mr. Voyles identifies a portion of Project 31 as the "vertical expansion of the ash treatment basin's north, south and west dikes." Does the east dike currently have the elevation planned for the other dikes? If no, explain why the east dike is not included in the project.

b. On page 31, Mr. Voyles discusses MACTEC's report on modifying the Trimble County ash basin. Describe, generally, the process under which MACTEC was selected to perform this work.

A-6. a. The east dike of the existing BAP was constructed to the original and final design elevation during the original construction of Trimble County Unit 1 when it was placed in service in 1990. The north, south, and west dikes will be raised to match the current elevation of the east dike.

b. The analysis of the storage needs at Trimble County was competitively bid to local Civil and Geotechnical Engineering firms with experience in developing CCP storage facilities in 2007 and again in 2008. Companies included in the competitive RFP process were MACTEC, ATC, and Stantec (formerly FMSM). See also the response to Question No. 24.

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Question No. 7

Witness: John N. Voyles, Jr.

Q-7. Refer to pages 31-36 of the Voyles Testimony regarding the Trimble County landfill (Project 32). On pages 33-34, Mr. Voyles discusses the MACTEC report on the preliminary conceptual design of the landfill and that MACTEC has been retained to develop the permit application for Project 32. Describe, generally, the process under which MACTEC was selected to perform this work.

A-7. The analysis of the storage needs at Trimble County was competitively bid to local Civil and Geotechnical Engineering firms with experience in developing CCP storage facilities in 2007 and again in 2008. Companies included in the competitive RFP process were MACTEC, ATC, and Stantec (formerly FMSM). See also the response to Question No. 24.

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Question No. 8

Witness: John N. Voyles, Jr.

Q-8. Refer to page 42 of the Voyles Testimony and page 19 of Exhibit JNV-2. Project 33 includes two barge load-out facilities to transport beneficial reuse byproduct: one owned by Synthetic Materials; the other owned by KU and Louisville Gas and Electric Company.

a. Were opportunities pursued to lease or co-own the second barge load-out facility with Synthetic Materials so that the companies could avoid the capital costs thereof? Explain the response.

b. Explain whether the proposed barge load-out area will exclusively be used for beneficial reuse activities and not used for other operational activities.

A-8. a. Two facilities are required due to the unique physical characteristics of the materials being moved. Fly ash will be pneumatically conveyed and blown into barges while gypsum will be conveyed and dropped into the barges. The Synthetic Materials contract, including the construction of the infrastructure for gypsum loadout, was executed in December of 2007 while the Holcim contract is still in discussion.

b. Yes, both barge loading facilities, the Synthetic Materials owned facility for gypsum and the KU/Louisville Gas and Electric owned facility for fly ash, will be dedicated for the exclusive loading of gypsum and fly ash associated with the respective beneficial reuse opportunities.

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Question No. 9

Witness: John N. Voyles, Jr.

Q-9. Refer to page 7 of Exhibit JNV-2, the June 2009 Comprehensive Strategy for Managing Coal Combustion Byproducts, which includes discussion of the steps taken by the company subsequent to the December 2008 breach of the containment dike at the Kingston generating station of the Tennessee Valley Authority. One of the steps was to retain ATC Associates ("ATC") to perform an independent third-party assessment of the company's impoundment facilities. ATC did not detect any safety deficiencies under normal loading conditions with any of the impoundments.

a. Explain how ATC was selected for this work and provide a description of its background and qualifications relevant to this type of work.

b. The last paragraph on page 7 of Exhibit JNV-2 indicates that more robust inspections of all impoundments will be performed by the company in 2009. Given that approximately two-thirds of calendar year 2009 has passed, what is the timetable for these inspections?

A-9. a. Bids to conduct and document visual assessments of KU and LG&E's high and moderate hazard dams were sent to three different Companies. The bid responses were evaluated based on price, proposed scope, ability to meet a short time-schedule, technical expertise and historical experience with E.ON U.S. ATC was the successful bidder from this process.

ATC is a multi-disciplined engineering consulting firm with experts in dam safety. ATC conducted assessments using professional geotechnical engineers that each had over thirty years of experience in dam design, analysis, remediation and safety inspections.

b. Inspections associated with the 12 KU/LG&E impoundment facilities classified as dams are scheduled to be complete by November 15, 2009; KU anticipates the final reports by the end of the first quarter 2010. KU will provide copies of the final reports to the Commission upon receipt.

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Question No. 10

Witness: Charles R. Schram

Q-10. Refer to page 15 of Exhibit CRS-1 to the Direct Testimony of Charles R. Schram ("Schram Testimony"). Identify and describe the basis for the 7.74 percent KU/LG&E discount rate and the 7.81 percent Kentucky Utilities discount rate included in the analysis assumptions for Project 28.

A-10. In preparing the data responses, KU discovered inadvertent typographical errors on page 15 of Exhibit CRS-1. Please see the corrected page 15 attached to this response.

The analysis of Project #28 uses three different discount rates. A discount rate of 7.81 percent was used to discount the cash flows associated with building the SCR at Brown, which will be wholly owned by KU. This rate was calculated as the weighted average cost of capital using the electric capitalization and debt rate applicable to KU at the end of 2008 and the 10.63 percent return on equity approved in the 2008 rate case (Case No. 2008-00251). The calculation of this discount rate is shown in the following table (as of 12/31/2008).

	KU Electric Capitalization *($000)*	**Percent of Total Capitalization**	**Cost Rate**	**Weighted Average Cost Rate**
Short-Term Debt	16,247	0.49%	1.49%	0.01%
Long-Term Debt	1,531,779	46.52%	4.67%	2.17%
Common Equity	1,744,720	52.99%	10.63%	5.63%
Total	**3,292,746**	**100.00%**		**7.81%**

The second portion of the analysis evaluated the effect of the decision to build an SCR at Brown and considered the impact to the capacity expansion plan of both KU and LG&E. For the KU-owned portion of the expansion plan, the previously mentioned discount rate of 7.81 percent was used. For the LG&E-owned portion, a discount rate of 7.64 percent was used. The LG&E rate was calculated as the weighted average cost of capital using LG&E's electric capitalization and debt rate at the end of 2008 and the 10.63 percent return on equity approved in the

2008 rate case (Case No. 2008-00252). The calculation of this discount rate is shown in the following table (as of 12/31/2008).

	LG&E Electric Capitalization *($000)*	Percent of Total Capitalization	Cost Rate	Weighted Average Cost Rate
Short-Term Debt	221,999	9.43%	1.49%	0.14%
Long-Term Debt	896,104	38.08%	5.04%	1.92%
Common Equity	1,234,988	52.49%	10.63%	5.58%
Total	**2,353,091**	**100.00%**		**7.64%**

Lastly, in order to calculate the present value of the revenue requirements for the entire study period (in 2009 dollars), the combined company discount rate of 7.74 percent was used. This rate was calculated as the weighted average cost of capital using KU and LG&E's total electric capitalization and debt figures at the end of 2008 and the 10.63 percent return on equity approved in the 2008 rate cases (Case No. 2008-00251 and 2008-00252). The calculation of this discount rate is shown in the following table (as of 12/31/2008).

	Total KU/LG&E Electric Capitalization *($000)*	Percent of Total Capitalization	Cost Rate	Weighted Average Cost Rate
Short-Term Debt	238,246	4.22%	1.49%	0.06%
Long-Term Debt	2,427,883	43.00%	4.81%	2.07%
Common Equity	2,979,708	52.78%	10.63%	5.61%
Total	**5,645,837**	**100.00%**		**7.74%**

Analysis Assumptions

- Study Period: 30-year period for Production Cost impacts (2009-2038)
  30-year period for Capital Costs impacts (2009-2038)

  The production costs include items such as fuel, O&M, purchase power etc and are estimated using the PROSYM™ production model. The model was run for the 2009-2038 time period.

  The revenue requirements associated with capital costs are determined via the Capital Expenditure and Recovery module of the Strategist production and capital costing software.

- KU/LGE continues as a regulated entity subject to the oversight of the Kentucky Public Service Commission and that the Commission continues the requirement of the Companies implementing the least cost strategy to the benefit of the native load ratepayers.

- The capital costs, O&M costs and the costs of increased emissions (both NOx and SO_2) associated with the addition of new environmental projects will be subject to recovery through the Environmental Cost Recovery mechanism.

- Fuel Forecast (Base Assumptions)
  Any and all fuel cost savings associated with serving native load will be returned to the ratepayers though the Fuel Adjustment Clause mechanism.

- Load Forecast includes impact of current recession, January 2009 perspective.

- Financial Data

➢ Discount Rate / AFUDC Rate	
o KU	7.81%
o LG&E	7.64%
o Joint KU/LG&E	7.74 %
➢ Percentage of Debt in Capital Structure	
o KU	47.01%
o LG&E	47.51%
o Joint KU/LG&E	47.22%
➢ Debt Cost	
o KU	4.64%
o LG&E	4.34%
o Joint KU/LG&E	4.51%
➢ Return on Equity	10.63%
➢ Income Tax Rate	38.9%
➢ Insurance Rate	0.053 %
➢ Property Tax Rate	0.15 %
➢ Environmental Projects Book Life	30 years
➢ Environmental Projects Tax Life	20 years

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Question No. 11

Witness: Charles R. Schram

Q-11. Refer to page 14 of Exhibit CRS-2 to the Schram Testimony. Identify and describe the basis for the 7.81 percent discount rate and the 6.0 percent annual capital and O&M escalation rate included in the analysis assumptions for Project 29.

A-11. The discount rate for Project #29, which is owned by KU, was calculated as the weighted average cost of capital using the electric capitalization and debt rate applicable to KU at the end of 2008 and the 10.63 percent return on equity approved in the 2008 rate case (Case No. 2008-00251). The calculation of this discount rate is shown in the following table (as of 12/31/2008).

	KU Electric Capitalization *($000)*	Percent of Total Capitalization	Cost Rate	Weighted Average Cost Rate
Short-Term Debt	16,247	0.49%	1.49%	0.01%
Long-Term Debt	1,531,779	46.52%	4.67%	2.17%
Common Equity	1,744,720	52.99%	10.63%	5.63%
Total	**3,292,746**	**100.00%**		**7.81%**

The annual escalation rate of 6 percent is calculated as a weighted average of the estimated escalation rates for diesel and petroleum based products, labor, and bulk materials. This calculation is shown in the following table.

	Escalation Rate	Percent of Total	Weighted Average Escalation Rate
Diesel/Petroleum Based Materials	7.3%	30%	2.2%
Labor	5.4%	35%	1.9%
Bulk Materials	5.5%	35%	1.9%
Total		**100%**	**6.0%**

The escalation rate for diesel / petroleum based materials is based on the NYMEX forward market price of West Texas Intermediate crude oil through 2014 as of

February 2009 and the 2003-2007 average ratio of retail diesel prices to crude oil. The labor escalation rate is the construction cost index for common labor as published in the Engineering News Record on February 9, 2009. The rate for bulk materials is calculated as the average of 6.5 percent for electric materials, 5 percent for concrete, and 5 percent for mechanical bulks. The rates for materials are based on forecasts from construction contractors Fluor (KU FGD program) and Bechtel (TC2).

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Question No. 12

Witness: Charles R. Schram

Q-12. Refer to page 26 of Exhibit CRS-4 to the Schram Testimony. Identify and describe the basis for the 7.76 percent discount rate included in the analysis assumptions for Project 32.

A-12. The discount rate for Project #32, which is for the KU and LG&E joint-owned Trimble County station, was calculated as the weighted average cost of capital using the weighted average of KU and LG&E's electric capitalization and debt rate at the end of 2008 based on the Companies' respective ownership shares of the capacity of the two coal units at the Trimble County station and the 10.63 percent return on equity approved in the 2008 rate cases (Case No. 2008-00251 and 2008-00252). The calculation of this discount rate is shown in the following table (as of 12/31/2008).

	Electric Capitalization					
	KU	LG&E	Trimble County Composite	Percent of Total Capitalization	Cost Rate	Weighted Avg. Cost Rate
Trimble Cty. Ownership	48%	52%				
Short-Term Debt	16,247	221,999	123,238	4.39%	1.49%	0.07%
Long-Term Debt	1,531,779	896,104	1,201,228	42.84%	4.86%	2.08%
Common Equity	1,744,720	1,234,988	1,479,659	52.77%	10.63%	5.61%
Total	**3,292,746**	**2,353,091**	**2,804,125**	**100.00%**		**7.76%**

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Question No. 13

Witness: John N. Voyles, Jr. / Shannon L. Charnas

Q-13. Refer to page 3 of the Direct Testimony of Shannon L. Charnas. Clarify whether the incremental aspects of Projects 29 and 31, or some other reason, explains why no O&M costs for those projects will be recovered through KU's environmental surcharge.

A-13. It is expected that there will be no material change in the level of O&M expenses as a result of Project No. 29, Brown Storage Basin and Project No. 31, Trimble County Storage Basin, therefore, the Company has not requested recovery of O&M expenses related to these projects through the ECR mechanism.

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Question No. 14

Witness: Shannon L. Charnas / Robert M. Conroy

Q-14. Refer to page 6 of the Charnas Testimony, which indicates that projects in the 2009 compliance plan could affect operation and maintenance expenses associated with coal combustion byproducts. List the accounts that could be affected and describe, generally, the process that will be used to determine the level of such expenses to be recovered through KU's ECR mechanism rather than through its base rates.

A-14. Ongoing comparisons will be made between the level of expenses in base rates and the level of expenses for any project included in the ECR. Compliance and consistency with Commission orders will be maintained to ensure that there is no double recovery of O&M costs through the ECR mechanism and base rates.

The accounts associated with the recovery of coal combustion byproducts costs through the ECR mechanism are 501, Ash Disposal and 502, Waste Disposal.

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Question No. 15

Witness: Robert M. Conroy

Q-15. Refer to page 1 of Exhibit RMC-5 to the Direct Testimony of Robert M. Conroy, which shows the impact of the 2009 compliance plan on the monthly bill of a residential customer for the years 2010 to 2014. Explain whether the 2009 compliance plan addresses all existing federal and state environmental requirements through 2014, or whether there are other existing environmental requirements that must be addressed by 2014 that could affect a customer's bill beyond what is included in the exhibit.

A-15. KU chose to include the summary of the estimated bill impact of the 2009 Plan through 2014 because after 2014, assuming only investments as outlined in the current filing, the billing factor is forecast to begin declining. Details for each project were also included in Exhibit RMC-5 through 2018. However, while KU at this time is not aware of significant additional investment that may be required to comply with current environmental regulation, KU does not intend to imply that no additional investment will be necessary in the future. KU continuously reviews its obligations for environmental compliance and if appropriate will file for additional projects through the ECR.

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Question No. 16

Witness: Lonnie E. Bellar

Q-16. In the Bellar Testimony, page 12, line 15, Mr. Bellar refers to Exhibit LEB-1. Provide a copy of LEB-1.

A-16. KU clarifies that there is not an Exhibit LEB-1; the reference was a placeholder for a table describing the history and current capacities of KU's ash treatment facilities. Since the same information is presented in Mr. Voyles's testimony and exhibits, KU elected not to include the information as an exhibit to Mr. Bellar's testimony, but neglected to remove the reference. The referenced information can be found in Exhibit JNV-2.

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Question No. 17

Witness: John N. Voyles, Jr.

Q-17. In the Voyles Testimony, page 8, line 19, Mr. Voyles states, "EPA has conducted two separate studies, reaching a conclusion in 1993 and again in 2000 that CCP did not warrant regulation as a hazardous waste." Has this opinion changed since 2000?

A-17. No. Since the failure of a TVA ash pond in Kingston, Tennessee in December 2008, EPA has undertaken an effort to gather information on a number of utility CCP management facilities across the nation and evaluate conditions associated with those facilities. EPA has also announced that it is reviewing the current regulatory program applicable to CCP's to determine if changes are appropriate. EPA is reportedly considering a variety of potential regulatory options ranging from continued regulation of CCP's under the current regulatory program to regulation of CCP's under the hazardous waste program. To date, EPA has not proposed regulation of CCP's under the hazardous waste program or any other changes to the current regulatory program. However, EPA has not yet completed its review.

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Question No. 18

Witness: John N. Voyles, Jr.

Q-18. In Exhibit JNV-2, Page 3, first paragraph, next-to-last sentence, there is a statement that "opportunities for beneficial reuse of Coal Combustion byproducts have shifted from a net revenue position to a net cost position". When did this take place? Explain.

A-18. Historically, many Coal Combustion byproducts (CCPs) were sold by generators to end users resulting in a revenue stream particularly in the case of the sale of synthetic gypsum. New governmental regulations were enacted that caused utilities to install sulfur dioxide removal systems, resulting in increased volumes of synthetic gypsum, so that supply is now in excess of demand. Also, many utilities' on-site storage facilities have been reaching design storage capacity and thus many have been using more aggressive marketing techniques including payments to take CCPs offsite.

The largest single demand for synthetic gypsum is as a replacement for natural gypsum in the production of wallboard. Other uses include; as an additive in the cement making process and as soil amendments for agricultural purposes. As the economy started declining and consumer demand for wallboard and cement decreased, the production of synthetic gypsum was increasing due to the retrofit of flue gas desulfurization systems. As a result, the supply of synthetic gypsum exceeded the demand. Many utilities began paying users to take their product, especially those utilities with high on-site disposal costs. Based on the Company's experience, the shift from a revenue stream to a cost stream for CCP reuse began to occur during 2008.

As other utilities' storage options are exhausted and their costs for disposal increase many have begun paying a subsidy to users. Utilities that are closest to the user certainly have a transportation cost advantage, but many times the subsidy being offered by one utility makes the use uneconomic and uncompetitive for another utility with lower disposal costs.

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Question No. 19

Witness: John N. Voyles, Jr.

Q-19. In Exhibit JNV-2 page 11, explain how cost saving relates to "net cost".

A-19. Cost savings as indicated in the 1st paragraph on page 11 of Exhibit JNV-2 is in reference to lower future costs. Cost savings associated with beneficial reuse come primarily through avoided CCP disposal costs such as delaying the construction of new or expanded impoundments or landfills. The Company is expecting to incur additional investments and expenses associated with managing CCP and economical beneficial reuse opportunities provide a way to reduce, not eliminate, the financial impact (i.e., net costs) of those future management activities.

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Question No. 20

Witness: John N. Voyles, Jr.

Q-20. In Exhibit JNV-2, page 7, second paragraph, last sentence, there is reference to a report prepared by ATC Associates on impoundments that the Kentucky Department of Environmental Protection classifies as low-hazard. Provide a copy of this report.

A-20. The requested report "Q20 ATC Low Hazard Dams Assessment Report signed 20090319" is included on the enclosed compact disc.

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Question No. 21

Witness: John N. Voyles, Jr.

Q-21. In Exhibit JNV-2, page 7, third paragraph, last sentence, there is a reference to a report on non-classified facilities. Provide a copy of this report.

A-21. The current draft of the requested report "Q21 ATC Non Classified Report" is included on the enclosed compact disc.

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Question No. 22

Witness: Charles R. Schram

Q-22. Refer to the Schram Testimony, page 6. Since 80 percent of the gypsum will be used (beneficial reuse plan) to construct the embankments on the main and auxiliary ash treatment basins at E.W. Brown Station, what would be the results if the beneficial reuse of the gypsum was greater to an outside source?

A-22. Transporting gypsum off-site and an alternative fill material on-site will result in a higher overall cost for the project. In the event that gypsum produced at Brown would be sent to an outside source for beneficial reuse, KU would pay the cost of loading and delivering the gypsum to the outside source and also pay to have fill material (dirt, etc.) purchased, delivered and placed for the construction of the embankments. KU's plan to beneficially reuse CCP for on-site construction eliminates the need to transport the CCP off-site and transport fill material on-site. The remote location of the Brown station will increase the cost of potential beneficial reuse opportunities due to the cost of transporting CCP from the plant.

The 80 percent of gypsum production to be used as fill material is an estimate. It is possible that the percentage of gypsum used in the construction of the storage basins will exceed 80 percent.

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Question No. 23

Witness: Charles R. Schram

Q-23. In the CCP Plan for E.W. Brown Station, "NEEDS ASSESSMENT", page 6, tons of ash are converted to cubic yards of ash. Provide the dry weights and specific gravity of the products that you used to make these conversions. Also provide the same for gypsum. Provide the same results for all stations if different dry weights and specific gravities were used.

A-23. For converting the weight in tons of CCP produced to volume in cubic yards as stored, the dry density of each CCP was used based on whether the storage method was "wet" as in an impoundment or "dry" as in a landfill. The following table shows the dry density assumptions that were used for each type of CCP for each storage method at each station. Specific gravities were not used in the calculations. The dry density assumptions are based on our experience and while these conversions can vary, alternative calculations were not derived.

Dry Density *(tons/cubic yard)*						
	Fly Ash		**Bottom Ash**		**Gypsum/FCS***	
Storage Method	**Wet**	**Dry**	**Wet**	**Dry**	**Wet**	**Dry**
Brown	0.95	N.A.	0.95	N.A.	1.01	N.A.
Ghent	1.01	1.08	0.95	1.22	1.01	1.22
Trimble County	0.88	1.15	1.08	N.A.	0.95	1.22
Cane Run	1.01	1.22	1.01	1.32	N.A.	0.87

**FCS: Fixated Calcium Sulfite is produced at LG&E's Cane Run Station*

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Question No. 24

Witness: John N. Voyles, Jr.

Q-24. Did KU send a request for proposal ("RFP") for each of the projects listed in the application?

a. If yes, provide a copy of the RFP, the responses, and to whom it was sent.

b. If no.

(1) Explain why an RFP was not necessary and explain how the estimated costs for each project were derived.

(2) Explain whether an RFP for each project will be issued prior to the beginning of construction.

A-24. Yes.

The Company has a Corporate Purchasing Policy that specifies the purchase amount at which the competitive bidding process is required. A copy of that policy is attached to this response; please see Attachment 1.

a. The following is a description of KU's process the engineering and construction of the CCP Projects included in the application. Due to the volume of material, the referenced documents are being provided on compact disc. The Award Recommendations referenced are being provided pursuant to a petition for confidential protection.

Engineering Contract Award Process

E.ON U.S. issues an RFP to local, regional, and national engineering firms with prior experience in designing CCP storage facilities. Prior to issuing an RFP package, E.ON U.S. will enter into a General Service Agreements (GSA) with each of the bidders which identifies unit rates and Terms & Conditions for the project. Based on the information attained during the GSA process, engineering unit rates are similar across the various bidders. Given this, other factors affect the evaluation of award at each Plant. The Engineering firms knowledge of a Plant's geology, design of existing CCP structures, the quality of the design team submitted, availability of the Engineering firm to meet each Project's requirements, and other categories can affect the decision of award. Below is a general description of the RFP process that has been utilized in awarding the engineering work to date:

- Issue RFP to 3-4 bidders.
- Hold a mandatory pre-bid meeting 2 weeks after the RFP is issued.
- Bids will be due between 4-6 weeks after the RFP is issued.
- Short list the bids based on cost, technical capabilities, prior work experience, knowledge of the Plant, etc.
- Hold at least one bid review meeting with each short listed bidder. Additional meeting will be held if necessary.
- Upon completion of the bid review meetings an Engineer will be chosen based on several criteria such as cost, technical capabilities, safety, financial strength, schedule, etc.
- From start to finish the RFP process can take anywhere between 2-3 months depending on the complexity of the project and completeness of the bids.

A detailed description of the engineering RFP process for each project is provided below:

Brown ATB

- Initial Siting Study – Was sole sourced to Stantec (formerly FMSM). This was awarded after review of rates to other Engineers and a determination that FMSM had specific knowledge of the Brown ATB due to their involvement with the site for decades. See the file "EWB Initial Siting Purchase Order" in the Q24/CCP Engineering/EW Brown folder on the enclosed compact disc.
- Conceptual Design – An RFP was issued to Stantec, MACTEC, and Burns & McDonnell with the work being awarded to Stantec. See the files "EWB Ash Pond Extension RFP," "EWB Ash Pond Cover Memo REDACTED," "EWB Engineering Cost Evaluation Matrix REDACTED" and "EWB Engineering Cost Comparison REDACTED" in the Q24/CCP Engineering/EW Brown folder on the enclosed compact disc. Confidential information has been redacted.
- Detailed Design – Was a continuation of the Conceptual Design and awarded to Stantec. See the file "EWB Engineering Detailed Design SSA REDACTED" in the Q24/CCP Engineering/EW Brown folder on the enclosed compact disc. Confidential information has been redacted.
- Final Detailed Design – Was included in the Detailed Design RFP.

Ghent Landfill

- Initial Siting Study – An RFP was issued to GAI, MACTEC, ATC, URS, Burns & McDonnell and Stantec with the work being awarded to GAI. See the files "Ghent CCP Initial Siting Study RFQ" and "Ghent Siting Study Bid Evaluation REDACTED" in the Q24/CCP Engineering/Ghent folder on the enclosed compact disc. Confidential information has been redacted..
- Conceptual Design – An RFP was issued to GAI, MACTEC, ATC, and Stantec with the work being awarded to GAI. See the files "Ghent CCP Final Conceptual Design RFQ" and "Ghent Final Conceptual Design Award Red REDACTED" in the Q24/CCP Engineering/Ghent folder on the enclosed compact disc. Confidential information has been redacted..
- Detailed Design – Due to time constraints the Conceptual Design and Detailed Design was consolidated into one RFP package.
- Final Detailed Design – Was included in the Conceptual and Detailed Design RFP.

Trimble County BAP/GSP

- Initial Siting Study – An Initial Siting study was not performed for this project due to the structures already existing.
- Conceptual Design – The Conceptual Design was performed by MACTEC under the Trimble County Landfill Project.
- Detailed Design – Was sole sourced to MACTEC due to availability and work performed on the Landfill project. See the file "TC MACTECH SSA REDACTED" in the Q24/CCP Engineering/Trimble Co folder on the enclosed compact disc. Confidential information has been redacted.
- Final Detailed Design – Was included in the Detailed Design RFP.

Trimble County Landfill

- Initial Siting Study – An RFP was issued to MACTEC, ATC, and Stantec with the work being awarded to MACTEC. See the file "Trimble County Landfill RFP" in the Q24/CCP Engineering/Trimble Co folder on the enclosed compact disc. .
- Conceptual Design – Was sole sourced to MACTEC to maintain continuity on the project. the file "TC MACTECH addendum REDACTED" in the Q24/CCP Engineering/Trimble Co folder on the enclosed compact disc. Confidential information has been redacted.
- Detailed Design – Was sole sourced to MACTEC to maintain continuity on the project. the file "TC MACTECH addendum 2 REDACTED" in the Q24/CCP Engineering/Trimble Co folder on the enclosed compact disc. Confidential information has been redacted.
- Final Detailed Design – Was included in the Detailed Design RFP.

As listed above, Engineering for the CCP projects was awarded to several engineering firms (Stantec, MACTEC and GAI). A major factor in this was the fact that having several Geotech Engineers working on the CCP Projects throughout KU/LG&E's Plants ensures the avoidance of a fatal flaw in design not being duplicated on other projects by the same Engineer. It also reduces the execution risk from a single Engineer being overloaded with work and it allows "best practices" obtained on one Project to be shared on other Projects by having a broader range of Engineers designing and permitting the CCP Projects..

While various Engineering firms were utilized on the Projects, Project Engineering established a common set of cost estimating standards for use on all the projects. At the direction of E.ON U.S., the various Engineering firms utilized RS Means Heavy Construction estimating manual and past experience when developing cost estimate to maintain continuity between the projects.

Construction Contract Award Process

The RFP process to award the construction contract for the various CCP projects is similar to the RFP process utilized for the engineering contracts except for the number of bidders and durations. E.ON U.S. issues an RFP to local and regional construction firms with prior experience in heavy civil, landfill, and pond construction. Below is a general description of the RFP process that has been utilized in awarding the construction work to date:

- Issue RFP to no less than 3-4 bidders.
- Hold a mandatory pre-bid meeting approximately 2 weeks after the RFP is issued.
- Bids are usually due between 2-3 months after the RFP is issued based on the complexity of the project.
- E.ON U.S. with the assistance of the Engineer short- lists the bids down to a smaller field based on cost, technical capabilities, safety, team proposed, availability, schedule, knowledge of the Plant, as well as other criteria.
- At least one bid review meeting will be held with each short-listed bidder. Additional meeting will be held if necessary.
- Upon completion of the bid review meetings a contractor will be chosen based on several criteria such as cost, technical capabilities, safety, financial strength, schedule, etc.
- From start to finish the RFP process can take anywhere between 3-6 months depending on the complexity of the project and completeness of the bids.

A detailed description of construction RFP process for each project to date is provided below:

Brown ATB Phase I

- Aux Pond 880' – RFP package was issued to Hall Contracting, Allen Company, Bizzack, Hinkle, Charah, and LMS with the contract being awarded to Bizzack. See the files in the Q24/CCP Construction /EW Brown/Aux Pond RFP for the RFP and bid related documents. Also see the file "EWB Aux pond 880 award rec-REDACTED," all on the enclosed compact disc. Confidential information has been redacted...
- Main Pond Starter Dike – RFP package was issued to Hall Contracting, Allen Company, Bizzack, Hinkle, Charah, and Summit with the contract being awarded to Summit. See the files in the Q24/CCP Construction /EW Brown/Main Pond RFP for the RFP and bid related documents. Also see the file "EWB Main Pond Starter Dike award rec-REDACTED," all on the enclosed compact disc. Confidential information has been redacted...

Brown ATB Phase II

No construction RFP packages have been issued to date. Aux Pond 900' RFP package will be issued in the fourth quarter of 2009.

Ghent Landfill

No construction RFP packages have been issued to date as the project is currently in the Final Design phase.

Trimble County BAP/GSP

RFP package was issued to Riverside, Evans Construction, W.B. Koester, Summit, Hinkle, and T&C Contracting with the contract being awarded to Riverside. See the files "TC BAP RFP" and "Trimble BAP Award Rec REDACTED" in the Q24/CCP Construction /Trimble Co folder on the enclosed compact disc. Confidential information has been redacted..

Trimble County Landfill

No construction RFP packages have been issued to date as the project is currently in the Conceptual Design phase.

For Project 28, the SCR Technology RFP has been issued to Riley Power, Hitachi, Doosan, Mitsubishi, Alston and B&W. Bids have been received and are currently under review. Clarifications to the bidders' responses have been issued and their responses to KU's and LG&E's clarification request have been received. An award for the SCR Technology is expected in the Fall of 2009. The RFP for the EPC construction contract has been issued and bids are not due until November 2, 2009. The EPC RFP request lump sum bids from Fluor, Bechtel, Zachry, TIC and Shaw. Once bids are received, the evaluation and negotiation period is expected to take several months with an award in January/February 2010. Copies of the SCR Technology RFP and EPC RFP can be found in the Q24/EW Brown SCR folder on the enclosed compact disc. Confidential information has been redacted.

The bid responses are typically voluminous in nature (e.g., 200 to 500 pages) and may contain charts, graphs, drawings or maps that are not readily reproducible. The bid responses also contain confidential and proprietary information that is not publically disclosed by KU or LG&E. The Award Recommendations containing the analysis of the bids are being produced pursuant to a petition for confidential treatment. The specific bids are available for review at the Companies' offices or will be produced pursuant to a petition for confidential treatment upon request.

b. Not applicable

E.ON U.S. LLC Policy

Purchasing

Policy

The Company shall at all times, without prejudice, seek to obtain the maximum value available for every purchase of a good or service.

Scope

This policy applies to all E.ON U.S. LLC. and subsidiaries' (Company) employees, temporary workers, and contractors, on or off Company property, procuring goods or services on behalf of the Company at any time.

General Requirements

1. All procurement of goods or services shall be made by purchase order or contract or a company credit card. Specific exceptions to these requirements are listed below.
2. All goods and services shall be procured from one of the following:
   - A material supplier that has been qualified in the Vendor database to provide goods, or
   - A service provider that has been certified as part of the Company's formal contractor certification process.

Deviation from this policy will require the completion of the Intent to Deviate from E.ON U.S. Terms and Conditions.

3. Competitive bidding is the preferred method of procuring goods and services. All goods and services valued in excess of $50,000 require competitive bidding. Deviations from this policy will require the completion of a properly approved Sole Source Authorization document. For the purposes of compliance with the policy, a properly reviewed and signed Investment proposal will be considered a suitable substitute for the Sole Source Authorization.
4. All procurement activities and approvals should be made in accordance with the Authority Limit Matrices and the Purchasing Guidelines.
5. All procurement activities must adhere to the Company's Code of Business Conduct.
6. The Company shall comply with all applicable federal, state and local laws, statutes, rules and regulations, and shall require that all suppliers with whom it does business comply with them as well.
7. The Company will encourage and support the development of businesses owned by minorities and women as competitive sources of goods and services.
8. Independent contractors or consultants shall meet the conditions established by the Internal Revenue Service.
9. The Legal Department has developed a set of standard terms and conditions for E.ON U.S. contracts. Standard terms and conditions for contracts shall be used at all times.

Any revisions to such terms must be initiated, reviewed and approved by the Legal Department.

10. The Director of Supply Chain is the only authorized signing agent for the company. Only the Director of Supply Chain (or an appointed designee) can commit the company to a purchase of goods or a contract for services, consistent with the Delegation of Authority guidelines. The Director of Supply Chain will designate other employees as authorized signing agents as appropriate,. The list of authorized Company signing agents is contained in Note 24 of the Corporate Authority Limit Matrices. No other employee is authorized to sign contracts, letters of intent, purchase orders, agreements or enter into verbal commitments or otherwise indicate that they have the authority to act on the Company's behalf.
11. The Company shall not begin work or receive material prior to the issuance of a fully executed purchase order or contract, except in an emergency.
12. Records must be maintained in accordance with the Company's Records Management - Preservation and Retention of Records policy.
13. The Supply Chain Department has established guidelines (Purchasing Guidelines) for the purchase of all goods and services. These Purchasing Guidelines are incorporated into this policy by reference.
14. Any contract not within the normal course of business requires approval of the Executive Vice President, General Counsel and Corporate Secretary of E.ON U.S. Corp.

Exceptions to the General Requirements

1. Contracts or purchase orders are not required for:
   - Utility payments (electric, gas, water, MSD, cell phone, land line phone, pagers, etc.),
   - Federal, state and local taxes, vehicle and similar licenses, permits, fines, assessment, postage and other payments to the government
   - Travel and entertainment
   - Miscellaneous officers' expenses
   - Donations, contributions and sponsorships
   - Customer or vendor refunds,
   - Professional and membership dues
   - Attorney fees and other legal expense associated with litigation
   - External audit and tax fees including the cost of tax returns (consulting by accounting or auditing firms are not exempt)
   - Insurance payment (health, liability)
   - Bank fees and other financial transaction fees related to Treasury
   - Certain expatriate expenses
   - Inter-company settlements

- Trade shows, charity and community events
- Foreign currency payment requests
- Petty cash reimbursement
- Procurement card purchases
- Freight charges
- Drug Screening Tests
- Miscellaneous charges as approved by a Supply Chain manager.

(See Disbursements Policy)

2. The following activities are covered under separate policies and are not governed by the Purchasing Policy:
    - Fuel procurement
    - Purchase power contracts
    - Real estate transactions including property rental and leases
    - LPI Projects and MRMD transactions
    - E.ON US Foundation
    - Defined benefit and contribution plans and other similar agreements

3. The CEO and any designee of the CEO are exempted from General Requirement 10.

Penalties For Noncompliance

Failure to comply with this policy may result in disciplinary action, up to and including dismissal.

Reference: Code of Business Conduct, Purchasing Guidelines, Authority Limit Matrices, Procurement Card Policy, Records Management – Preservation and Retention of Records, Disbursements Policy

Key Contact: Director, Supply Chain

Administrative Responsibilities: Chief Financial Officer

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Question No. 25

Witness: John N. Voyles, Jr.

Q-25. Is KU aware of any other use for the byproduct other than what is listed in its application? Explain the response.

A-25. No. Please see the beneficial reuse discussion on page 10 of Exhibit JNV-2.