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PUBLIC SERVICE
COMMISSION

Ms. Elizabeth O'Donnell
Executive Director
Kentucky Public Service Commission
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Kent W. Blake
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May 4, 2007

RE: ***Application of Kentucky Utilities Company for an Order Authorizing Inclusion of Investment Tax Credits in Calculation of Environmental Surcharge and Declaring Appropriate Ratemaking Methods for Base Rates*** **– Case No. 2007-00** 178

Dear Ms. O'Donnell:

Enclosed please find and accept for filing the original and ten (10) copies of Kentucky Utilities Company's Application and Testimony in the above-referenced matter.

Should you have any questions concerning the enclosed, please do not hesitate to contact me.

Sincerely,

Kent W. Blake

Kent W. Blake

cc: Hon. Dennis G. Howard, II
Hon. Michael L. Kurtz

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MAY 0 4 2007

PUBLIC SERVICE COMMISSION

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

APPLICATION OF KENTUCKY UTILITIES COMPANY FOR AN ORDER AUTHORIZING INCLUSION OF INVESTMENT TAX CREDITS IN CALCULATION OF ENVIRONMENTAL SURCHARGE AND DECLARING APPROPRIATE RATEMAKING METHODS FOR BASE RATES	)	**CASE NO. 2007-00178**

APPLICATION OF
<u>KENTUCKY UTILITIES COMPANY</u>

Kentucky Utilities Company ("KU") hereby petitions the Kentucky Public Service Commission ("Commission") by application, pursuant to 807 KAR 5:001, to issue a declaratory order approving (1) the inclusion in the calculation of the environmental surcharge of that portion of KU's advanced coal project investment tax credit that is related to environmental projects approved for recovery through the environmental surcharge, (2) the revised ES Forms 2.00 and 2.10, and (3) the proposed rate base and capitalization treatments of the investment tax credit and the proposed allocation of Kentucky jurisdictional rate base to be the appropriate ratemaking methods for the determination of base rates. In support of this Application, KU states as follows:

1. <u>Address</u>: The Applicant's full name and business address is: Kentucky Utilities Company, One Quality Street, Lexington, Kentucky 40507. KU's mailing address is Kentucky Utilities Company c/o Louisville Gas and Electric Company, Post Office Box 32010, 220 West Main Street, Louisville, Kentucky 40232.

2. <u>Articles of Incorporation</u>: A certified copy of KU's Articles of Incorporation are on file with the Commission in Case No. 2005-00471, *In the Matter of: Application of*

Louisville Gas and Electric Company and Kentucky Utilities Company for Authority to Transfer Functional Control of their Transmission System, filed on November 18, 2005, and is incorporated by reference herein pursuant to 807 KAR 5:001, Section 8(3).

3. KU is a public utility, as defined in KRS 278.010(3)(a), engaged in the electric business. KU generates and purchases electricity, and distributes and sells electricity at retail in the following counties in Central, Northern, Southeastern and Western Kentucky:

Adair	Edmonson	Jessamine	Ohio
Anderson	Estill	Knox	Oldham
Ballard	Fayette	Larue	Owen
Barren	Fleming	Laurel	Pendleton
Bath	Franklin	Lee	Pulaski
Bell	Fulton	Lincoln	Robertson
Bourbon	Gallatin	Livingston	Rockcastle
Boyle	Garrard	Lyon	Rowan
Bracken	Grant	Madison	Russell
Bullitt	Grayson	Marion	Scott
Caldwell	Green	Mason	Shelby
Campbell	Hardin	McCracken	Spencer
Carlisle	Harlan	McCreary	Taylor
Carroll	Harrison	McLean	Trimble
Casey	Hart	Mercer	Union
Christian	Henderson	Montgomery	Washington
Clark	Henry	Muhlenberg	Webster
Clay	Hickman	Nelson	Whitley
Crittenden	Hopkins	Nicholas	Woodford
Daviess			

4. On December 17, 2004, KU and Louisville Gas and Electric Company ("LG&E") (collectively, the "Companies") applied for, and by Order dated November 1, 2005, in Case No. 2004-00507, the Commission granted, a certificate of public convenience and necessity to construct Trimble County Unit No. 2 ("TC2").[1] TC2 will be a state-of-the-

[1] *In the Matter of Joint Application of Louisville Gas and Electric Company and Kentucky Utilities Company for a Certificate of Public Convenience and Necessity, and a Site Compatibility Certificate, for the Expansion of the Trimble County Generating Station*, Case No. 2004-00507.

art, super-critical, pulverized coal-fired generating unit that will employ the latest technology to achieve extraordinary efficiency and low environmental impact.

5. On August 8, 2005, the federal Energy Policy Act of 2005 became law. (Energy Policy Act of 2005, 42 U.S.C. §§ 15801-16524 (2005)). The Act created several investment tax credits designed to spur the development and construction of certain kinds of generation facilities. One such credit is the Qualifying Advanced Coal Project Credit (see 26 U.S.C. § 48A), which allows the Secretary of the Treasury to grant up to $1.3 billion in tax credits to advanced coal projects, $800 million for integrated gasification combined-cycle projects and $500 million for projects using other advanced coal-based generation technologies.

6. The Qualifying Advanced Coal Project Credit statute (26 U.S.C. § 48A) sets out two key categories of criteria for eligibility to receive an advanced coal-based generation technology credit ("'05 EPA ITC"): high-efficiency and low-emissions. Specifically, to qualify a project must: (1) have a "design net heat rate of 8530 Btu/kWh (40 percent efficiency)"; and (2) be designed to remove 99% of sulfur dioxide and 90% of mercury, and emit no more than 0.07 lbs of nitrous oxide and 0.015 lbs of particulate matter per MMBtu.[2] The qualifying advanced coal project also must meet these general criteria: have a nameplate rating of 400 Mw or greater, use at least 75% coal for fuel, have 50% or more electrical power output, and be located at one site.

7. In response to the enactment of 26 U.S.C. § 48A, on March 13, 2006, the U.S. Internal Revenue Service issued Internal Revenue Service Notice 2006-24 ("Notice"), which "establishe[d] the qualifying advanced coal project program under § 48A(d) of the Internal Revenue Code." Among other things, the Notice set out the procedures for applying for the

[2] 26 U.S.C. § 48A(f).

'05 EPA ITC. (A copy of Internal Revenue Service Notice 2006-24 is attached hereto as Exhibit 1.)

8. On June 28, 2006, KU and LG&E jointly filed an application with the U.S. Department of Energy ("DoE") to obtain a $125 million '05 EPA ITC for the construction of TC2. In their application, the Companies described in detail TC2's design, and particularly why it meets the requirements of ¶ 6 above (among others). (A copy of the DoE application (without its attachments)[3] is attached hereto as Exhibit 2.) On September 27, 2006, the Companies submitted an application for the credit to the U.S. Internal Revenue Service ("IRS"), along with additional certification documents that, if the IRS approved the Companies' application, would allow the Companies to begin claiming the tax credits as eligible expenditures are made.[4] (A copy of the IRS application (without its Exhibit 1 attachment)[5] is attached hereto as Exhibit 3.) On October 27, 2006, the IRS notified the Companies that the TC2 project received DoE certification. (A copy of the IRS certification letter is attached hereto as Exhibit 4.)

9. On November 29, 2006, the IRS informed the Companies that it too had accepted the Project's application and had allocated a total advanced coal project credit of $125 million. (A copy of the decision is attached hereto as Exhibit 5.)

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[3] The attachments consist of 50 pounds of paper documents, a number of which are documents on file at the Commission or are technical drawings and specifications for the design and construction of Trimble County Unit No. 2. An index of the attachments is set forth at pages 6 through 8 of the DoE application.

[4] According to the IRS, at this time, the request for "certification" of the TC2 generation facility (e.g., evidence that all permits have been obtained, major contracts completed, etc.) is under review and consideration at the Houston IRS Field Office for appropriate action. Certification must be received within two years of being allocated the credit, but does not prohibit the Company from claiming progress expenditures at this time. The approval of the certification application is not expected to be an issue because TC2 is already under construction.

[5] Exhibit 1 to the IRS Application is the DoE Application referenced in this filing as Exhibit 2.

10. On March 22, 2007, the IRS approved a Closing Agreement required in connection with claiming the $125 million tax credit. (A copy of the Closing Agreement is attached hereto as Exhibit 6.)[6]

11. The relevant part of the '05 EPA ITC statute provides that any property that is part of an advanced coal-based generation project is "eligible property", the basis of which is a qualified investment upon which a 15% credit may be claimed.[7] The statute further provides that the default time for claiming such credits is when the eligible property is placed in service; however, the law also makes provision for "qualified progress expenditures" that allow the credits to be claimed in the years that the Companies make expenditures for certain "eligible property."[8] The Companies anticipate that nearly all of their approximately $988 million in TC2 costs will be "qualified progress expenditures," meaning that the Companies will be able to take their 15% credit for the tax years in which they make the expenditures. Because the anticipated tax basis for TC2 is projected to be $988 million, the Companies anticipate that they will be able to avail themselves of the full $125 million '05 EPA ITC they have been awarded.

12. Because Illinois Municipal Electric Agency and Indiana Municipal Power Agency will not receive any portion of the '05 EPA ITC, KU and LG&E will share the credit in proportion to their respective ownership interests in TC2. Thus, KU's pro rata share of the '05 EPA ITC will be 81 percent of $125,000,000, which is $101,250,000.

13. KU must give its pro rata share of the '05 EPA ITC the same rate treatment that it had afforded all post-1971 investment tax credits pursuant to an election KU made

[6] The IRS sent the Closing Agreement on March 30, 2007; LG&E and KU received the IRS letter with the Closing Agreement on April 9, 2007.
[7] *See* 26 U.S.C. § 48A(a)(2), (b)(1) & (c)(3).
[8] *See* 26 U.S.C. § 48A(b)(1) & (3).

under former 26 U.S.C. § 46(f) in 1972, namely that KU will reduce its rate base by the amount of the credit it receives. (This is sometimes referred to as the "ratable restoration" method). Although 26 U.S.C. § 46(f) has since been repealed, it continues to apply to new investment tax credits such as the '05 EPA ITC through current 26 U.S.C. § 50(d)(2). Moreover, Internal Revenue Service Notice 2006-24 Section 2.05 explicitly states that 26 U.S.C. § 50 applies to this credit, thus requiring KU to continue to normalize such credits in its traditional fashion. Failure to normalize the credit would result in KU's having to forfeit the credit, among other possible negative consequences.[9]

14. The rate treatment KU must afford the '05 EPA ITC pursuant to its election under former 26 U.S.C. § 46(f) is long-standing and well-acknowledged as appropriate and necessary by the Commission. As early as 1981, in Case No. 8177 (a KU rate case), the Commission recognized that the appropriate treatment for an investment tax credit for KU was to reduce rate base by the amount of the credit.[10] Just a year and a half later in a separate KU rate case (Case No. 8624), the Commission approvingly recalled Case No. 8177, stating, "The 3 percent investment tax credits were included as a reduction to the rate base in Case 8177," and again included the investment tax credits at issue as a reduction to rate base.[11] In KU's latest rate case, Case No. 2003-00434, the Commission again recognized that investment tax credits appropriately reduced rate base.[12] This rate treatment of KU's investment tax credits is, therefore, both required by federal law and long-recognized by the Commission.

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[9] *See* current 26 U.S.C. §50(d)(2) and former 26 U.S.C. § 46(f).

[10] *In the Matter of General Adjustment of Electric Rates of Kentucky Utilities Company*, Case No. 8177, Order at 10-11 (September 11, 1981).

[11] *In the Matter of General Adjustment of Electric Rates of Kentucky Utilities Company*, Case No. 8624, Order at 3 (March 18, 1983).

[12] *In the Matter of an Adjustment of the Electric Rates, Terms, and Conditions of Kentucky Utilities Company*, Case No. 2003-00434, Order at 15 (June 30, 2004).

15. To normalize its portion of the '05 EPA ITC, KU will record (separately or as part of other periodic tax entries) on its financial statements: (1) a debit in FERC Account No. 236 - Taxes Accrued and a credit in FERC Account No. 409 - Federal Income Tax Expense; and (2) a debit in FERC Account No. 411.4 - Investment Tax Credit Adjustments and a credit in FERC Account No. 255 - Accumulated Deferred Investment Tax Credit. KU recorded entries in December 2006 with respect to the progress expenditure credits claimed in that year, and will continue to record entries through 2010, (projected in service date) for a total of $101,250,000 based on current estimates.

KU will also record on its balance sheet a debit to FERC Account No. 255 - Accumulated Deferred Investment Tax Credit, and a corresponding credit on its income statement to FERC Account No. 420 - Amortization of Investment Tax Credit. These amortization entries will begin when the unit goes into service for tax purposes (projected to be in 2010) and will continue over the regulatory life of the unit. The air quality control system and balance of the plant are currently estimated to have regulatory lives of 28.8 and 41.5 years, respectively.

16. KU will account separately for tax credits claimed on "eligible property" for air quality control systems and for the balance of plant costs as such categories of property have different regulatory lives.

17. Because KU's elected rate treatment method reduces KU's rate base by the amount of the investment tax credits it receives, KU proposes also to include in the calculation of its environmental surcharge a pro rata amount of its '05 EPA ITC associated with environmental pollution control equipment for TC2. The Commission approved the recovery of this project (Project No. 23) as part of KU's Environmental Surcharge

Compliance Plan in its December 22, 2006 Order in Case No. 2006-00206. Environmental pollution control equipment represents approximately 23% of the "qualified investment" in TC2.

18. KU proposes also to exclude the ECR rate base from Kentucky jurisdictional rate base, and to determine the percentage of Kentucky jurisdictional rate base (excluding ECR) to total company rate base when allocating capitalization in the next electric base rate case. Since the ECR revenue requirement is derived by the rate base methodology, this proposal provides consistency between Kentucky jurisdictional rate base and capitalization, as well as ensuring that the ECR rate base not recovered through base rates is excluded from the determination of base rates. KU has used this methodology for many years to allocate the appropriate amount of capital to its Kentucky and Virginia retail and wholesale jurisdictions. ECR revenues and expenses will continue to be excluded in the same manner as previously approved by the Commission and the Off-System Sales adjustment will also remain in the calculation of adjusted Net Operating Income.

19. The following direct testimony of KU's witnesses supports this Application:

- The testimony of Kent W. Blake, Vice President, State Regulation and Rates, E.ON U.S. Services Inc., describes how KU will provide its customers the benefit, consistent with Tax law, of its portion of the '05 EPA ITC, discusses a related ratemaking matter that arises from the recognition of the '05 EPA ITC in both the environmental surcharge and base rates to ensure no double counting of the credit, and presents revised ES Forms 2.00 and 2.10.

- The testimony of Mr. Ronald L. Miller, Director, Corporate Tax, E.ON U.S. Services Inc., (1) describes the investment tax credit at issue in this proceeding and summarizes the process by which KU obtained it; (2) describes the tax accounting treatment of the credit; and (3) states the adverse consequences of not following the rate treatment for the tax credit required by federal law.

WHEREFORE, Kentucky Utilities Company requests that the Commission issue an order: (1) authorizing the inclusion in the calculation of KU's environmental surcharge of that portion of KU's advanced coal project investment tax credit that is related to projects approved for recovery through the environmental surcharge; (2) approving the revised ES Forms 2.00 and 2.10; and (3) declaring the proposed rate base and capitalization treatments of the 2005 Energy Policy Act Investment Tax Credit and the proposed allocation of Kentucky jurisdictional rate base to be the appropriate ratemaking methods for the determination of base rates.

Dated: May 4, 2007

Respectfully submitted,

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Counsel for Kentucky Utilities Company

CERTIFICATE OF SERVICE

The undersigned hereby certifies that a true and correct copy of the foregoing Application was served on the following persons on the 4th day of May, 2007, U.S. mail, postage prepaid:

Dennis G. Howard, II Assistant Attorney General Office of the Kentucky Attorney General Office of Rate Intervention 1024 Capital Center Drive, Suite 200 Frankfort, KY 40601-8204	
Michael L. Kurtz Boehm Kurtz & Lowry 36 East Seventh Street, Suite 1510 Cincinnati, OH 45202	

Kendrick R. Riggs

Counsel for Kentucky Utilities Company

Part III - Administrative, Procedural, and Miscellaneous

Qualifying Advanced Coal Project Program

Notice 2006-24

SECTION 1. PURPOSE

This notice establishes the qualifying advanced coal project program under § 48A(d) of the Internal Revenue Code. The purpose of the program is the deployment of advanced coal-based generation technologies.

SECTION 2. BACKGROUND

.01 Section 46 provides that the amount of the investment credit for any taxable year is the sum of the credits listed in § 46. Section 1307(a) of the Energy Policy Act of 2005, Pub. L. 109-58, 119 Stat. 594 (August 8, 2005) (the "Act"), amended § 46 to add two new credits to that list: the qualifying advanced coal project credit and the qualifying gasification project credit.

.02 The qualifying advanced coal project credit is provided under § 48A, as added by § 1307(b) of the Act. Section 48A(a) provides that the qualifying advanced coal project credit for a taxable year is an amount equal to (1) 20 percent of the qualified investment (as defined in § 48A(b)) for that taxable year in certified qualifying advanced coal projects (as defined in § 48A(c)(1) and (e)) using an integrated gasification combined cycle (IGCC) (as defined in § 48A(c)(7)), and (2) 15 percent of the qualified investment for that taxable year in other certified qualifying advanced coal projects.

.03 Section 48A(d)(3)(A) provides that the aggregate credits allowed under § 48A(a) may not exceed $1.3 billion. Section 48A(d)(3)(B) provides that (i) $800 million of credits are to be allocated to IGCC projects, and (ii) $500 million of credits are to be allocated to projects that use other advanced coal-based generation technologies (as defined in § 48A(c)(2) and (f)).

.04 Section 48A(e)(3)(A) provides that the credits for IGCC projects must be allocated in accordance with the procedures set forth in § 48A(d), and in relatively equal amounts to (i) projects using bituminous coal as a primary feedstock, (ii) projects using subbituminous coal as a primary feedstock, and (iii) projects using lignite as a primary feedstock. Further, § 48A(e)(3)(B) provides that IGCC projects that include (i) greenhouse gas capture capability (as defined in § 48A(c)(5)), (ii) increased by-product utilization, and (iii) other benefits must be given high priority in the allocation of credits for IGCC projects.

.05 The at-risk rules in § 49 and the recapture and other special rules in § 50 apply to the qualifying advanced coal project credit. Further, the qualifying advanced coal project credit generally is allowed in the taxable year in which the eligible property (as defined in § 48A(c)(3)) is placed in service by the taxpayer. Pursuant to § 48A(D)(2)(E), a taxpayer that receives a certification under § 48A(d)(2)(D) has 5 years from the date of issuance of the certification to place the qualifying advanced coal project in service.

SECTION 3. QUALIFYING ADVANCED COAL PROJECT PROGRAM

Section 48A(d)(1) provides that the Secretary, in consultation with the Secretary of Energy, shall establish a qualifying advanced coal project program for the deployment of advanced coal-based generation technologies. The Treasury Department and the Internal Revenue Service are establishing this program under the rules set forth in sections 4 through 9 of this notice.

SECTION 4. ESTABLISHMENT OF QUALIFYING ADVANCED COAL PROJECT PROGRAM

.01 In General. The Service will consider a project under the qualifying advanced coal project program only if the U.S. Department of Energy ("DOE") provides a certification of feasibility and consistency with energy policy goals ("DOE certification") for the project. Accordingly, a taxpayer must submit, for each qualifying advanced coal project: (1) an application for certification by the DOE ("application for DOE certification"), and (2) an application for certification under § 48A(d)(2) by the Service ("application for § 48A certification"). Both applications may be submitted only during the 3-year period beginning on February 21, 2006. Certifications will be issued and credits will be allocated to projects in annual allocation rounds. The initial allocation round will be conducted in 2006. If necessary, additional allocation rounds will be conducted in 2007 and 2008.

.02 Program Specifications.

(1) The Service will determine the amount of the qualifying advanced coal project credits allocated to a qualifying advanced coal project at the time the Service accepts the application for § 48A certification for that project in

accordance with section 4.02(10) of this notice (see section 5 of this notice for the requirements applicable to the application for DOE certification and the application for § 48A certification).

(2) The qualifying advanced coal project credits of $1.3 billion and the applications for certification will be separated into the following four pools:

(a) Projects using an advanced coal-based generation technology other than IGCC. The aggregate amount of qualifying advanced coal project credit for this pool is $500 million. The maximum amount of credits that will be allocated to a project is $125 million.

(b) IGCC projects using bituminous coal as a primary feedstock. The aggregate amount of qualifying advanced coal project credit for this pool is $267 million. The maximum amount of credits that will be allocated to a project is $133.5 million.

(c) IGCC projects using subbituminous coal as a primary feedstock. The aggregate amount of qualifying advanced coal project credit for this pool is $267 million. The maximum amount of credits that will be allocated to a project is $133.5 million.

(d) IGCC projects using lignite as a primary feedstock. The aggregate amount of qualifying advanced coal project credit for this pool is $266 million. The maximum amount of credits that will be allocated to a project is $133 million.

(3) For projects using an advanced coal-based generation technology other than IGCC, the aggregate credit of $500 million for this pool as described in section 4.02(2)(a) of this notice will be allocated in the initial round of allocations

to projects providing the highest ratio of total nameplate generating capacity to requested allocation of credits.

(4) For each IGCC pool described in section 4.02(2)(b), (c), and (d) of this notice, the aggregate credit for that pool will be allocated as follows in the initial round of allocations:

(a) The aggregate credit will be allocated first to the projects entitled to priority under § 48A(e)(3)(B) for greenhouse gas capture capability or increased by-product utilization.

(b) If the requested allocation of credits for these priority projects exceeds the aggregate credit for the pool, the credit for that pool will be allocated to the priority projects providing the highest ratio of total nameplate generating capacity to requested allocation of credits.

(c) If the requested allocation of credits for the priority projects in a pool does not exceed the aggregate credit for the pool, the remaining amount of the credit will be allocated to the nonpriority projects providing the highest ratio of total nameplate generating capacity to requested allocation of credits.

(5) If the aggregate credit for a pool is not fully allocated in the initial round of allocations in 2006, similar allocation rounds will be conducted in 2007 and 2008 until the aggregate credit is fully allocated. Generally, the results of each year will be announced.

(6) If the same project would otherwise be allocated credits under both the qualifying advanced coal project program under this notice and the qualifying gasification project program under Notice 2006-25, 2006-11 I.R.B. ___, the

following rules apply:

(a) If the project is allocated the full amount of the qualifying advanced coal project credit requested by the taxpayer, no qualifying gasification project credit will be allocated to the project;

(b) If the project is allocated the full amount of the qualifying gasification project credit requested by the taxpayer, no qualifying advanced coal project credit will be allocated to the project;

(c) If the project is allocated less than the full amount of the qualifying advanced coal project credit requested by the taxpayer, the qualifying gasification project credit may be allocated to the project with respect to the qualified investment under § 48B for which a qualifying advanced coal project credit is not allowed under § 48A; and

(d) If the project is allocated less than the full amount of the qualifying gasification project credit requested by the taxpayer, the qualifying advanced coal project credit may be allocated to the project with respect to the qualified investment under § 48A for which a qualifying gasification project credit is not allowed under § 48B.

(7) For each allocation round there will be an annual application period during which a taxpayer may file its application for § 48A certification. The Service will consider a project in an allocation round only if the application for § 48A certification for the project is submitted during the application period for that round and the DOE provides the DOE certification for the project before the end of the application period.

(8) For the initial allocation round conducted in 2006, the application period begins on February 21, 2006, and ends on October 2, 2006. Any completed application for § 48A certification received by the Service before October 3, 2006, will be deemed to be submitted by the taxpayer on October 2, 2006. For 2007, the application period begins on October 3, 2006, and ends on October 1, 2007, and any completed application for § 48A certification received by the Service after October 2, 2006, and before October 2, 2007, will be deemed to be submitted by the taxpayer on October 1, 2007. For 2008, the application period begins on October 2, 2007, and ends on October 1, 2008, and any completed application for § 48A certification received by the Service after October 1, 2007, and before October 2, 2008, will be deemed to be submitted by the taxpayer on October 1, 2008. For purposes of this notice, an application that is submitted by U.S. mail will be treated as received by the Service on the date of the postmark and an application submitted by a private delivery service will be treated as received by the Service on the date recorded or the date marked in accordance with § 7502(f)(2)(C).

(9) See section 5.02 of this notice and Appendix B to this notice for the information to be submitted to the DOE in an application for DOE certification. Appendix B to this notice also provides the instructions and address for filing the application for DOE certification. The DOE will determine the feasibility of the project and its consistency with energy policy goals and, if the project is determined to be feasible and consistent with energy policy goals, will provide a DOE certification for the project to the Service. If an application for DOE

certification is postmarked on or before June 30 of a calendar year, the DOE will determine the feasibility of the project and its consistency with energy policy goals and (for projects determined to be feasible and consistent) provide the DOE certification by October 1 of that calendar year.

(10) By November 30 of the calendar year in which an application for § 48A certification is deemed to be submitted (as determined under section 4.02(8) of this notice), the Service will accept or reject the taxpayer's application for § 48A certification and will notify the taxpayer, by letter, of its decision.

(11) If the taxpayer's application for § 48A certification is accepted, the acceptance letter will state the amount of the credit allocated to the project. If a credit is allocated to a taxpayer's project, the taxpayer will be required to execute a closing agreement in the form set forth in APPENDIX A to this notice. By January 31 of the following year, the taxpayer must execute and return the closing agreement to the Service at the appropriate address listed in section 5.04 of this notice or listed in later guidance published in the Internal Revenue Bulletin. The Service will execute and return the closing agreement to the taxpayer by March 31 of such following year. The executed closing agreement applies only to the accepted taxpayer. Accordingly, any successor in interest must execute a new closing agreement with the Service. If the successor in interest does not execute a new closing agreement, the following rules apply:

(a) In the case of an interest acquired at or before the time the qualifying advanced coal project is placed in service, any credit allocated to the project will be fully forfeited (and rules similar to the recapture rules of § 50(a) apply with respect to qualified progress expenditures); and

(b) In the case of an interest acquired after the qualifying advanced coal project is placed in service, the project ceases to be investment credit property and the recapture rules of § 50(a) (and similar rules with respect to qualified progress expenditures) apply.

SECTION 5. APPLICATIONS FOR CERTIFICATIONS

.01 In General. An application for § 48A certification and a separate application for DOE certification must be submitted for each qualifying advanced coal project. If an application for DOE certification does not include all of the information required by section 5.02 of this notice and meet the requirements in sections 7.01 and 7.02 of this notice, the DOE may decline to accept the application. If an application for § 48A certification does not include all of the information listed in section 5.03 of this notice and meet the requirements in sections 7.01 and 7.02 of this notice, the application will not be accepted by the Service.

.02 Information Required in the Application for DOE Certification. An application for DOE certification must include all of the information requested in Appendix B to this notice and all of the following:

(1) The name, address, and taxpayer identification number of the taxpayer;

(2) The name and telephone number of a contact person;

(3) The name and address (or other unique identifying designation) of the qualifying advanced coal project;

(4) A statement specifying whether the project is an IGCC project or a qualifying advanced coal project that uses another advanced coal-based technology;

(5) In the case of an IGCC project, a statement specifying the type of coal (bituminous coal, subbituminous coal, or lignite) that will be the primary feedstock. An application for DOE certification with respect to an IGCC project will not be considered unless one of these types of coal is the primary feedstock. For purposes of § 48A(e)(3)(A), a type of coal is the primary feedstock only if at all times more than 50 percent of the cumulative total fuel input (coal and any other fuel input) for the project will consist of that type of coal;

(6) The estimated total cost of the project and the estimated total qualified investment in the eligible property that will be part of the project;

(7) The amount of the qualifying advanced coal project credit requested for the project. The amount requested must not exceed the maximum amount provided in section 4.02(2) of this notice;

(8) If the taxpayer is or will be requesting an amount of the qualifying gasification project credit under § 48B for the same project, a statement specifying the credit the taxpayer prefers to receive;

(9) A statement specifying whether the project is a new electric generation unit (as defined in § 48A(c)(6)), a retrofit of an existing electric generation unit, or a repower of an existing electric generation unit; and

(10) The exact total nameplate generating capacity of the project.

.03 Information Required in the Application for § 48A Certification.

Pursuant to § 48A(d)(2)(B), an application for § 48A certification must include all of the following:

(1) The name, address, and taxpayer identification number of the taxpayer;

(2) The name and telephone number of a contact person. If necessary, attach any required power of attorney, preferably on Form 2848, Power of Attorney and Declaration of Representative; and

(3) A paper copy of the completed application for DOE certification submitted with respect to the project in accordance with section 5.02 of this notice.

.04 Instructions and Address for Filing § 48A Application. Applications for § 48A certification should be marked: SECTION 48A APPLICATION FOR CERTIFICATION. There is no user fee for these applications.

(1) Applications submitted by U.S. mail must be sent to:

Internal Revenue Service
Attn: CC:PSI:6, Room 5313
P.O. Box 7604
Ben Franklin Station
Washington, DC 20044

Applications submitted by a private delivery service must be sent to:

Internal Revenue Service
Attn: CC:PSI:6, Room 5313
1111 Constitution Ave., N.W.
Washington, DC 20224

(2) Applications may also be hand delivered Monday through Friday between the hours of 8 a.m. and 4 p.m. to:

Courier's Desk

Internal Revenue Service
Attn: CC:PSI:6, Room 5313
1111 Constitution Avenue N.W.
Washington, DC 20224

SECTION 6. ISSUANCE OF CERTIFICATION

.01 In General. Section 48A(d)(2)(D) provides that a taxpayer shall have 2 years from the date of acceptance of the § 48A application during which to provide evidence that the criteria set forth in § 48A(e)(2) have been met. Pursuant to § 48A(e)(2), a project shall be eligible for certification only if (A) the taxpayer has received all federal and state environmental authorizations or reviews necessary to commence construction of the project, and (B) the taxpayer, except in the case of a retrofit or repower of an existing generation unit, has purchased or entered into a binding contract for the purchase of the main steam turbine or turbines for the project, except that this contract may be contingent upon receipt of a certification under § 48A(d)(2). Section 48A(d)(2)(E) provides that a taxpayer that receives a certification has 5 years from the date of issuance of the certification to place the project in service and that the certification is void if the project is not placed in service by the end of that five-year period.

.02 Requirements for Certification. Within 2 years from the date that the Service accepts the taxpayer's application for § 48A certification under section 4.02(10) of this notice, the taxpayer must submit to the Service documentation establishing that the requirements of § 48A(e)(2) are satisfied. See also sections 7.01 and 7.02 of this notice for other requirements that must be satisfied. The taxpayer should mark the package "SECTION 48A CERTIFICATION REQUIREMENTS" and send it to the appropriate address listed in section 5.04 of this notice or listed in later guidance published in the Internal Revenue Bulletin.

.03 Service's Action on Certification. After receiving the material in section 6.02 of this notice, the Service will decide whether or not to certify the project and will notify the taxpayer, by letter, of that decision. If the Service certifies the project, the date of this letter is the date of issuance of the certification.

SECTION 7. OTHER REQUIREMENTS

.01 Signature. Each submission under sections 5 and 6 of this notice must be signed and dated by the taxpayer. A stamped signature or faxed signature is not permitted.

.02 Penalties of Perjury Statement.

(1) Each submission under sections 5 and 6 of this notice must be accompanied by the following declaration: "Under penalties of perjury, I declare that I have examined this submission, including accompanying documents, and, to the best of my knowledge and belief, all of the facts contained herein are true, correct, and complete."

(2) The declaration must be signed and dated by the taxpayer. The person signing for the taxpayer must have personal knowledge of the facts. A stamped signature or faxed signature is not permitted.

.03 Effect of an Acceptance, Allocation, or Certification. An acceptance, allocation, or certification by the Service under this notice is not a determination that a project qualifies for the qualifying advanced coal project credit under

§ 48A. The Service may, upon examination (and after any appropriate consultation with DOE), determine that the project does not qualify for this credit.

.04 No Right to a Conference or Appeal. A taxpayer does not have a right to a conference relating to any matters under this notice. Further, a taxpayer does not have a right to appeal the decisions made under this notice (including the acceptance or rejection of the application for DOE or § 48A certification, the amount of credit allocated to the project, or whether or not to certify the project) to an Associate Chief Counsel or any other official of the Service.

SECTION 8. REVIEW AND REDISTRIBUTION

.01 In General. Section 48A(d)(4)(A) provides that the credits allocated under § 48A must be reviewed not later than August 8, 2011. Pursuant to § 48A(d)(4)(B), credits available under § 48A(d)(3)(B)(i) and (ii) may be reallocated if (i) there is an insufficient quantity of qualifying applications for certification pending at the time of the review; or (ii) any certification made pursuant to § 48A(d)(2) has been revoked pursuant to § 48A(d)(2)(D). If credits under § 48A(d)(3)(B)(i) and (ii) are available for reallocation, § 48A(d)(4)(C) authorizes the conduct of an additional program for applications for certification.

.02 Review and Redistribution of Credits.

(1) In general. If, after the allocation round in 2008, the entire credit for a pool is not fully subscribed (i.e., the aggregate credit for the pool has not been fully allocated), the remaining credits from that pool will be reallocated to pools that have been fully subscribed. Credits from pools not fully subscribed will be reallocated to fully subscribed pools in proportion to the aggregate amounts of

credit specified for the fully subscribed pools in section 4.02(2) of this notice. Future guidance will prescribe the procedures applicable to applications for certification with respect to the reallocated credits.

(2) Reduction or forfeiture of allocated credits. Under the closing agreement set forth in Appendix A to this notice, the qualifying advanced coal project credits allocated under section 4 of this notice will be reduced or forfeited in certain situations. A taxpayer must notify the Service of the amount of any reduction or forfeiture required under the closing agreement. This notification must be sent to the appropriate address listed in section 5.04 of this notice or listed in later guidance published in the Internal Revenue Bulletin.

The amount of any reduction or forfeiture of the allocated credits will be returned to the appropriate allocation pool and included in the aggregate credit remaining to be allocated in the allocation round following the reduction or forfeiture. If the reduction or forfeiture occurs after the allocation round in 2008, future guidance will prescribe procedures applicable to applications for certification with respect to the returned credits.

SECTION 9. QUALIFIED PROGRESS EXPENDITURES

.01 Section 48A(b)(3) provides that rules similar to the rules of § 46(c)(4) and (d) (as in effect on the day before the enactment of the Revenue Reconciliation Act of 1990) shall apply for purposes of § 48A. Former §§ 46(c)(4) and 46(d) provided the rules for claiming the investment credit on qualified progress expenditures (as defined in former § 46(d)(3)) made by a taxpayer during the taxable year for the construction of progress expenditure property (as defined in former § 46(d)(2)).

.02 In the case of self-constructed property (as defined in former § 46(d)(5)(A)), former § 46(d)(3)(A) defined qualified progress expenditures to mean the amount that is properly chargeable (during the taxable year) to capital account with respect to that property. With respect to a qualifying advanced coal project that is self-constructed property, amounts paid or incurred are chargeable to capital account at the time and to the extent they are properly includible in computing basis under the taxpayer's method of accounting (for example, after applying the requirements of § 461, including the economic performance requirement of § 461(h)).

.03 To claim the qualifying advanced coal project credit on the qualified progress expenditures paid or incurred by a taxpayer during the taxable year for construction of a qualifying advanced coal project, the taxpayer must make an election under the rules set forth in § 1.46-5(o) of the Income Tax Regulations. A taxpayer may not make the qualified progress expenditures election for a qualifying advanced coal project until the taxpayer has received an acceptance letter for the project under section 4.02(10) of this notice.

.04 If a taxpayer makes the qualified progress expenditures election pursuant to section 9.03 of this notice, rules similar to the recapture rules in § 50(a)(2)(A)-(D) apply. In addition to the cessation events listed in § 50(a)(2)(A), examples of other events that will cause the project to cease being a qualifying advanced coal project are:

(1) Failure to satisfy any of the certification requirements in § 48A(e)(2)

within 2 years from the date that the Service accepted the taxpayer's application for § 48A certification for the project under section 4.02(10) of this notice;

(2) Failure to receive a certification for the project in accordance with section 6.03 of this notice;

(3) Failure to place the project in service within 5 years from the date of issuance of the certification under section 6.03 of this notice; or

(4) In the case of an IGCC project that was entitled to priority under § 48A(e)(3)(B), failure to provide the priority benefit on the date the project is placed in service.

SECTION 10. EFFECTIVE DATE

This notice is effective February 21, 2006.

SECTION 11. PAPERWORK REDUCTION ACT

The collection of information contained in this notice has been reviewed and approved by the Office of Management and Budget in accordance with the Paperwork Reduction Act (44 U.S.C. 3507) under control number 1545-2003.

An agency may not conduct or sponsor, and a person is not required to respond to, a collection of information unless the collection of information displays a valid OMB control number.

The collections of information in this notice are in sections 4, 5, 6, 7, 8, and Appendix B of this notice. This information is required to obtain an allocation of qualifying advanced coal project credits. This information will be used by the Service to verify that the taxpayer is eligible for the qualifying advanced coal project credits. The collection of information is required to obtain a benefit. The likely respondents are business or other for-profit institutions.

The estimated total annual reporting burden is 4,950 hours.

The estimated annual burden per respondent varies from 70 to 150 hours, depending on individual circumstances, with an estimated average of 110 hours. The estimated number of respondents is 45.

The estimated annual frequency of responses is on occasion.

Books or records relating to a collection of information must be retained as long as their contents may become material in the administration of any internal revenue law. Generally, tax returns and tax return information are confidential, as required by 26 U.S.C. 6103.

SECTION 12. DRAFTING INFORMATION

The principal author of this notice is Douglas H. Kim of the Office of Associate Chief Counsel (Passthroughs & Special Industries). For further information regarding this notice contact Mr. Kim at (202) 622-3110 (not a toll-free call).

APPENDIX A

CLOSING AGREEMENT

Under § 7121 of the Internal Revenue Code, [insert taxpayer's name, address, and identifying number] ("Taxpayer") and the Commissioner of Internal Revenue ("Commissioner") make the following closing agreement:

WHEREAS:

1. On or before October [insert date and year], Taxpayer submitted to the Internal Revenue Service ("IRS"), an application for certification under the qualifying advanced coal project program described in Notice 2006-24 ("Application for § 48A Certification");

2. Taxpayer's Application for § 48A Certification is for the qualifying advanced coal project (the "Project") described below--

(1) The Project will use [insert either "an integrated gasification combined cycle (as defined in § 48A(c)(7))" or "an advanced coal-based technology (as defined in § 48A(c)(2) and (f)) other than an integrated gasification combined cycle"];

(2) The Project will be located at [insert address or other identifying designation];

(3) The Project is [insert either: "a new electric generation unit (as defined in § 48A(c)(6))"; "a retrofit of an existing electric generation unit (as defined in § 48A(c)(6))"; or "a repower of an existing electric generation unit (as defined in § 48a(c)(6)");

(4) The Project will have a total nameplate generating capacity of [insert number] megawatts;

[If the Project is an integrated gasification combined cycle project, insert:

(5) At all times more than 50 percent of the cumulative total fuel input (coal and any other fuel input) for the Project will be [insert either: "bituminous coal"; "subbituminous coal"; or "lignite"];

(6) The Project is entitled to priority under § 48A(e)(3)(B) for [insert either: "greenhouse gas capture capability (as defined in § 48A(c)(5))"; "increased by-product utilization"; or "both greenhouse gas capture capability (as defined in § 48A(c)(5)) and increased by-product utilization"];**]** and

3. On or before November 30, [insert year], the IRS accepted Taxpayer's Application for § 48A Certification for the Project and allocated a qualifying advanced coal project credit under § 48A in the amount of $[insert number] to the Project.

NOW IT IS HEREBY DETERMINED AND AGREED FOR FEDERAL INCOME TAX PURPOSES THAT:

1. The total amount of the qualifying advanced coal project credit to be claimed for the Project under § 48A(a) must not exceed $[insert the number in WHEREAS clause #3].

2. If Taxpayer fails to satisfy any of the certification requirements in § 48A(e)(2) within 2 years of [insert date of acceptance letter issued under section 4.02(10) of Notice 2006-24], or if the IRS does not issue a certification for the Project under Notice 2006-24, the qualifying advanced coal project credit in

the amount of $[insert the number in WHEREAS clause #3] allocated to the Project is fully forfeited.

3. If the Project is not placed in service by Taxpayer within 5 years of the date of issuance of the certification as determined under section 6.03 of Notice 2006-24, the qualifying advanced coal project credit in the amount of $[insert the number in WHEREAS clause #3] allocated to the Project is fully forfeited.

4. If the Project does not have a total nameplate generating capacity of [insert the number in WHEREAS clause #2(4)] megawatts on the date the Project is placed in service, the qualifying advanced coal project credit in the amount of $[insert the number in WHEREAS clause #3] allocated to the Project is reduced proportionately.

[If the Project is not an integrated gasification combined cycle project, insert:

5. If the Project fails to satisfy any of the requirements in § 48A(e)(1) for a qualifying advanced coal project--

(1) at the time the Project is placed in service, the qualifying advanced coal project credit in the amount of $[insert the number in WHEREAS clause #3] allocated to the Project is fully forfeited; and

(2) after the Project is placed in service (and after satisfying all such requirements at the time the Project is placed in service), the Project ceases to be investment credit property and the recapture rules of § 50(a) apply.**]**

[If the Project is an integrated gasification combined cycle project, insert:

5. (1) If the Project fails to satisfy any of the requirements in § 48A(e)(1)

for a qualifying advanced coal project--

(a) at the time the Project is placed in service, the qualifying advanced coal project credit in the amount of $[insert the number in WHEREAS clause #3] allocated to the Project is fully forfeited; and

(b) after the Project is placed in service (and after satisfying all such requirements at the time the Project is placed in service), the Project ceases to be investment credit property and the recapture rules of § 50(a) apply.

(2) If at any time more than 50 percent of the cumulative total fuel input (coal and any other fuel input) for the Project is not [insert the primary feedstock in WHEREAS clause #2(5)], the Project ceases to be investment credit property and the recapture rules of § 50(a) apply.

(3) If the Project fails to provide [insert priority benefits in WHEREAS clause #2(6)] at the time the Project is placed in service, the qualifying advanced coal project credit in the amount of $[insert the number in WHEREAS clause #3] allocated to the Project is fully forfeited.]

6. Taxpayer will not claim the qualifying gasification project credit under § 48B for any qualified investment for which the qualifying advanced coal project credit is allowed under § 48A.

7. If Taxpayer elects to claim the qualifying advanced coal project credit on the qualified progress expenditures paid or incurred by Taxpayer during the taxable year for construction of a qualifying advanced coal project, rules similar to the recapture rules in § 50(a)(2)(A) through (D) apply.

8. This agreement applies only to Taxpayer. Any successor in interest

must execute a new closing agreement with the IRS. If the interest is acquired at or before the time the Project is placed in service and the successor in interest fails to execute a new closing agreement, the qualifying advanced coal project credit in the amount of $[insert the number in WHEREAS clause #3] allocated to the Project is fully forfeited. If the interest is acquired after the time the Project is placed in service and the successor in interest fails to execute a new closing agreement, the Project ceases to be investment credit property and the recapture rules of § 50(a) apply.

THIS AGREEMENT IS FINAL AND CONCLUSIVE EXCEPT:

1. The matter it relates to may be reopened in the event of fraud, malfeasance, or misrepresentation of a material fact;

2. It is subject to the Internal Revenue Code sections that expressly provide that effect be given to their provisions (including any stated exception for § 7122) notwithstanding any law or rule of law; and

3. If it relates to a tax period ending after the date of this Closing Agreement, it is subject to any law enacted after such date, which applies to the tax period.

By signing, the parties certify that they have read and agreed to the terms of this Closing Agreement.

Taxpayer: [insert name and identifying number]

By: ______________________________ **Date Signed:** ___________

[insert name]

Title: [insert title]
[insert taxpayer's name]

Commissioner of Internal Revenue

By: ______________________________ **Date Signed:** ___________
[insert name]

Title: Associate Chief Counsel, Passthroughs and Special Industries, CC:PSI

I have examined the specific matters involved and recommend the acceptance of the proposed agreement.

(Receiving Officer) ....

(Title) ....

Date Signed ....

I have reviewed the specific matters involved and recommend the acceptance of the proposed agreement.

(Reviewing Officer) ....

(Title) ....

Date Signed ....

APPENDIX B

APPLICATION FOR DOE CERTIFICATION

REQUEST FOR SUPPLEMENTAL APPLICATION INFORMATION FOR DOE

Pursuant to Notice 2006-24 establishing the Qualifying Advanced Coal Project Program, the Internal Revenue Service ("IRS") will allocate a credit under § 48A of the Internal Revenue Code to a project only if, among other things, the IRS receives from the Department of Energy ("DOE") a certification of feasibility and consistency with energy policy goals ("DOE certification") for the project. This DOE certification shall assure that the applications selected meet the requirements of § 48A and the intent of § 48A to provide credits to projects that are both technically and economically feasible.

The IRS and DOE seek to certify applications that demonstrate a high likelihood of being successfully implemented by the applicants. To qualify, projects must be economically feasible and use the appropriate clean coal technology.

This request for submission of supplemental application information:

1. Describes the information to be provided by the applicant seeking a DOE certification, and
2. Lists the evaluation criteria, and Program Policy Factors to be used by DOE in the evaluation of applications.

In conducting this evaluation, the DOE may utilize assistance and advice from qualified personnel from other Federal agencies and/or non-conflicted contractors. DOE will obtain assurances in advance from all evaluators that application information shall be kept confidential and used only for evaluation purposes. DOE reserves the right to request clarifications and/or supplemental information from some or all applicants through written submissions and/or oral presentations.

Notice is given that DOE may determine whether or not to provide a DOE certification to the IRS at any time after the application has been received, without further exchanges or discussions. Therefore, all applicants are advised to submit their most complete and responsive application.

Applications will not be returned.

SUBMISSION INFORMATION FOR DOE CERTIFICATION APPLICATION

A. *General*

This request, together with the information in sections 5.02, 7.01, and 7.02 of Notice 2006-24 includes all the information needed to complete an application for DOE certification. All applications shall be prepared in accordance with this request in order to provide a standard basis for evaluation and to ensure that each application will be uniform as to format and sequence.

Each application should clearly demonstrate the applicant's capability, knowledge, and experience in regard to the requirements described herein.

Applicants should fully address the requirements of Notice 2006-24 and this request and **not** rely on the presumed background knowledge of reviewers. DOE may reject an application that does not follow the instructions regarding the organization and content of the application when the nature of the deviation and/or omission precludes meaningful review of the application.

B. Unnecessarily Elaborate Applications

Unnecessarily elaborate brochures or other presentations beyond those sufficient to present a complete and effective application are not desired. Elaborate art work, graphics and pictures are neither required nor encouraged.

C. Application Submission for DOE Certification

The application submission to DOE must include the information and documentation required by sections 5.02, 7.01, and 7.02 of Notice 2006-24.

A project will not be considered in the allocation round conducted in a calendar year unless the application for DOE certification of the project is postmarked by June 30 of that calendar year. Two paper copies and one electronic version on a floppy disc or a CD of the Application must be submitted to:

Melissa Robe
National Energy Technology Laboratory
3610 Collins Ferry Road
Morgantown, WV 26507

Note that under section 5 of Notice 2006-24, one paper copy must be sent to the IRS as part of the application for IRS certification. The project will not be considered in the allocation round conducted in a calendar year unless the application is submitted to the IRS by the date specified for that calendar year in section 4.02(8) of Notice 2006-24.

THE INFORMATION REQUIRED BY THIS REQUEST MUST BE SUBMITTED USING THE FORMAT AND THE HEADINGS OF THE "PROJECT INFORMATION MEMORANDUM" AS DESCRIBED BELOW.

To aid in evaluation, applications shall be clearly and concisely written and logically assembled. All pages of each part shall be appropriately numbered and identified with the name of the applicant and the date.

The application, including the Project Information Memorandum, MUST be formatted in one of the following software applications:

Microsoft Word^{tm} 2002 or later edition

Microsoft Excel^{tm} 2002 or later edition

Adobe Acrobat^{tm} PDF 6.0 or later edition

Financial models should be submitted using the Excel^{tm} spreadsheet and must include calculation formulas and assumptions.

The applicant is responsible for the integrity and structure of the electronic files. The DOE will not be responsible for reformatting, restructuring or converting any files submitted under this announcement.

The Project Information Memorandum, excluding Appendices, shall not exceed seventy-five (75) pages. Pages in excess of the page limitation will not be considered for evaluation. All text shall be typed, single spaced, using 12 point font, 1 inch margins, and unreduced 8-1/2-inch by 11-inch pages. Illustrations and charts shall be legible with all text in legible font. Pages shall be sequentially numbered. Except as otherwise noted herein the page guidelines previously set forth constitute a limitation on the total amount of material that may be submitted for evaluation. No material may be incorporated in any application by reference as a means to circumvent the page limitation.

D. Form of Project Information Memorandum

PROJECT INFORMATION MEMORANDUM

I. SUMMARY AND INTRODUCTION

- Description of the Project
- Financing and Ownership Structure
- Describe the main parties to the project, including background, ownership and related experience
- Current Project Status and Schedule to Beginning of Construction

II. TECHNOLOGY AND TECHNICAL INFORMATION

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

- Provide evidence sufficient to demonstrate that the proposed technology meets the definition of "Advanced Coal-Based Generation Technology," either as integrated gasification combined cycle (IGCC) technology, or other advanced coal-based electric generation technology meeting the heat rate requirement of 8530 Btu/kWh

  - The applicant must provide actual heat rate and heat rate corrected to conditions specified in § 48A(f)(2)
  - For projects including existing units, the applicant must provide information sufficient to justify that the proposed technology meets heat rate requirements specified in § 48A(f)(3)

- Provide evidence sufficient to ensure that the proposed project is designed to meet the following performance requirements:
  - SO2 percent removal........99 percent
  - NOx emissions..............0.07 lbs / MMBTU
  - PM emissions................0.015 lbs / MMBTU
  - Hg percent removal..........90 percent
- Provide evidence sufficient to demonstrate that the project meets the requirements for qualifying advanced coal projects as specified under § 48A(e)(1) including:
  - The project will power a new electric generation unit or retrofit/repower an existing electric generation unit. At least 50% of the useful output of the project is electrical power.
  - The fuel for the project is at least 75% coal (as defined in § 48A(c)(4)), on an energy input basis.

    - The project is located at one site and has a total nameplate electric power generating capacity of at least 400 MW.
- Provide information and data, including examples of prior similar projects completed by applicant, EPC contractor, and suppliers of major subsystems or equipment which support the capabilities of the applicant to construct and operate the facility.
- Include the project status and relevant information from ongoing engineering activities. Also include in an appendix any engineering report or reports used by the applicant to develop the project and to estimate costs and operating performance.

III. PRIORITY FOR INTEGRATED GASFICIATION COMBINED CYCLE PROJECTS

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

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

- Other benefits, if any.

IV. SITE CONTROL AND OWNERSHIP

- Provide evidence that the applicant owns or controls a site in the United States of sufficient size to allow the proposed project to be constructed and operated on a long-term basis.
- Describe the current infrastructure at the site available to meet the needs of the project.
- Provide information supporting applicant's conclusion that the proposed site can fully meet all environmental, coal supply, water supply, transmission interconnect, and public policy requirements.

V. UTILIZATION OF PROJECT OUTPUT

- A projection of the anticipated costs of electricity and other marketable by-products produced by the plant.
- Provide evidence that a majority of the output of the plant is reasonably expected to be acquired or utilized.
- Describe any energy sales arrangements that exist or that may be contemplated, e.g., Power Purchase Agreement or Energy Sales Agreement, and summaries of their key terms and conditions.

- Include as an appendix any independent Energy Price Market Study that has been done in connection with this project, or if no independent market study has been completed, provide a copy of the applicant-prepared market study.
- Identify and describe any firm arrangements to sell non-power output, and provide any evidence of such arrangements. If the project produces a product in addition to power, include as an appendix any related market study of price and volume of sales expected for that product.

VI. PROJECT ECONOMICS

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

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

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

VII. PROJECT DEVELOPMENT AND FINANCIAL PLAN

Provide the total project budget and major plant costs, e.g., development, operating, capital, construction, and financing costs. Describe the overall approach to project development and financing sufficient to demonstrate project viability. Provide a complete explanation of the source and amount of project equity. Provide a complete explanation of the source and amount of project debt. Provide the audited financial statements for the applicant for the most recently ended three fiscal years, and the unaudited quarterly interim financial statements for the current fiscal year.

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

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

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

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

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

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

VIII. PROJECT CONTRACT STRUCTURE

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

- Power Purchase Agreement (if not fully explained in Section IV)
- Coal Supply: describe the source and price of coal supply for the project. Include as an appendix any studies of coal supply price and amount that have been prepared. Include a summary of the coal supply contract and a copy of the contract.
- Coal transportation: explain the arrangements for transporting coal, including costs.
- Operations & Maintenance Agreement: include a summary of the terms and conditions of the contract and a copy of the contract.
- Shareholders Agreement: summarize key terms and include the agreement as an appendix.
- Engineering, Procurement and Construction Agreement: describe the key terms of the existing or expected EPC contract arrangement, including firm price, liquidated damages, hold-backs, performance guarantees, etc.
- Water Supply Agreement: confirm the amount, source, and cost of water supply.

- Transmission interconnection agreement: explain the requirements to connect to the system and the current status of negotiations in this respect.

IX. PERMITS INCLUDING EVIRONMENTAL AUTHORIZATIONS

- Provide a complete list of all federal, state, and local permits, including environmental authorizations or reviews, necessary to commence construction of the project.
- Explain what actions have been taken to date to satisfy the required authorizations and reviews, and the status of each.
- Provide a description of the applicant's plan to obtain and complete all necessary permits, and environmental authorizations and reviews.

X. STEAM TURBINE PURCHASE

- If applicant plans to purchase a steam turbine or turbines for the project, indicate the prospective vendors for the turbine and explain the current status of purchase negotiations, and provide a timeline for negotiation and purchase with expected purchase date.

XI. PROJECT SCHEDULE

- Provide an overall project schedule which includes technical, business, financial, permitting and other factors to substantiate that the project will meet the 2 year project certification and 5 year placed-in-service requirement.

APPENDICES

- Independent Financial Report.
- Copy of internal or external engineering reports.
- Copy of site plan, together with evidence that applicant owns or controls a site. Examples of evidence would include a deed, or an executed contract to purchase or lease the site.
- Information supporting applicant's conclusion that the site is fully acceptable as the project site with respect to environment, coal supply, water supply, transmission interconnect, and public policy reasons.
- Power Purchase or Energy Sales Agreement.
- Energy Market Study.
- Market Study for non-power output.
- Financial Model of project.
- Audited financial statements for the applicant for the most recently ended three fiscal years, and the unaudited quarterly interim financial statements for the current fiscal year.

- For each project contract, if no contract currently exists, provide a summary of the expected terms and conditions.
- List of all federal, state, and local permits, including environmental authorizations or reviews, necessary to commence construction.

- If an appendix listed above is not provided, include in its place a complete explanation of the reasons for the omission.

E. *Evaluation Criteria*

Advanced coal projects: will be evaluated on whether they meet all the requirements of § 48A.

Technical: will be evaluated on whether the applicant has demonstrated the capability to accomplish the technical objectives.

Site: will be evaluated on the basis that the site requirement for ownership or control has been met, and that the site is suitable for the proposed project.

Economic: will be evaluated on whether the project has demonstrated economic feasibility, taking into consideration the submitted financial and project development and structural information and financial plan.

Schedule: will be evaluated on the applicant's ability to meet the 2 year project certification and the 5 year placed-in-service requirement.

F. Program Policy Factors to be used by DOE in the evaluation of applications and a description of how they will be applied.

These factors, while not indicators of the applicant's merit, e.g., technical excellence, cost, applicant's ability, etc., may be essential to the process of selecting the application(s) that, individually or collectively, will best achieve the objectives the authorizing legislation. Such factors are often beyond the control of the applicant. Applicants should recognize that some very good applications may not receive selection for certification because they do not fit within a mix of projects and technologies that maximize the probability of achieving the overall objective of deployment of advanced coal-based generation technology. Therefore, the following Program Policy Factors may be used individually or collectively by DOE following application of evaluation criteria to determine which of the applications shall receive certification by DOE.

- Diversity of technology approaches and methods
- Geographic distribution of potential markets
- Presentation of unique environmental, economic, or performance benefits

G. Instructions for independent financial reports

The applicant shall provide an independent report by a qualified Independent Financial Analyst (such as a bank, investment bank, or other independent financial advisory firm). In the report, the Independent Financial Analyst shall describe qualifications and experience that establish the Analyst's competence to evaluate project financing for projects similar in scope and size to the Applicant's project. The Independent Financial Analyst shall provide a thorough, independent review of the Applicant's approach to project financing. The report shall include the opinion of the Independent Financial Analyst as to the Applicant's likelihood to achieve financial closure in accordance with the Applicant's financing plan.

Required Certification by Independent Financial Analyst:

The report shall be certified by the Independent Financial Analyst, who shall (a) acknowledge that the report has been prepared for submission to the Department of Energy as a part of an application by applicant for an investment credit, and (b) certify that the Independent Financial Analyst has no obligation to the applicant and has acted to the best of its ability as an independent expert.

At a minimum, the Independent Financial Analyst shall:

- Review the financial model.
- Review the project financial assumptions, including economic, capital costs, operating assumptions, and all project development costs.
- Review the financial calculations, including rates of return and coverage ratios.
- Confirm the calculation of the amount of the tax credit applied for.
- Review the project development cost budget.
- Review and comment on the source of funding and evidence of funding.
- Review and comment on project debt and equity sources.
- Confirm that the application includes the required financial reports and debt ratings.
- Describe and comment on the capabilities of the applicant to provide the required financing for the project, and the likelihood of obtaining financing from a source other than the applicant, if such financing is required by the project.

APPLICATION FOR DEPARTMENT OF ENERGY CERTIFICATION

Applicant Name:	Kentucky Utilities Company and Louisville Gas and Electric Company
Applicant Address:	220 West Main Street, P. O. Box 32030 Louisville Kentucky 40232
Taxpayer identification number:	Kentucky Utilities Company 61-0247570 Louisville Gas and Electric Company 61-0264150
Contact Person:	Ronald L. Miller, Director Corporate Tax, (502) 627 - 2687 Gregory J. Meiman, Senior Counsel (502) 627 - 2562 J. Scott Williams, Manager Tax Accounting, (502) 627 - 2530
Qualified advanced coal project:	Trimble County Unit 2 487 Corn Creek Road Bedford, Kentucky 40006

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INDEX OF ABBREVIATIONS

ACI	Activated Carbon Injection
AQCS	Air Quality Control System
BACT	Best Available Control Technology
Bechtel	Bechtel Power Corporation
Btu/kWh	British Thermal Units per Kilowatt hour
Btu/Lb	British Thermal Units per Pound
$Ca(OH)_2$	Hydrated Lime
CCN	Certificate of Public Convenience and Necessity
CER	Capital Expenditure and Recovery
CO	Carbon Monoxide
CSR	Curtailment Service
CT	Combustion Turbine
DESP	Dry Electrostatic Precipitator
DOE	Department of Energy
DSM	Demand Side Management
EAF	Equivalent Availability Factor
E.ON	E.ON AG
E.ON U.S.	E.ON U.S. LLC
EPC	Engineering, Procurement & Construction
°F	Fahrenheit
FERC	Federal Energy Regulatory Commission
FGD	Flue Gas Desulfurization
GCOD	Guaranteed Commercial Operational Date
GWh	Gigawatt hour
H_2O	Water
H_2SO_4	Sulfuric Acid
HAL	Hitachi American Limited
HF	Hydrogen Fluoride
Hg	Mercury
HHV	Higher Heating Value
HP	High Pressure
I&O	Interconnection and Operating
IGCC	Integrated Gasification Combined Cycle
IMEA	Illinois Municipal Electric Agency
IMPA	Indiana Municipal Power Agency
IP	Intermediate Pressure
IRP	Integrated Resource Plan
IRS	Internal Revenue Service
ISO	Independent System Operator
KPDES	Kentucky Pollutant Discharge Elimination System

KPSC	Kentucky Public Service Commission
KU	Kentucky Utilities Company
Lb/MMBtu	Pound per Million British thermal units
Lb/MWh	Pound per Megawatt hours
LD	Liquidated Damages
LDC	Load Duration Curves
LG&E	Louisville Gas and Electric Company
LOI	Loss on Ignition/Unburned Carbon
LP	Low Pressure
MBEL	Mitsui Babcock Energy Ltd.
MISO	Midwest Independent Transmission System Operator
MMBtu	Million British thermal units
MMBtu/hr	Million British thermal units per hour
MW	Megawatts
MWH	Megawatt Hours
O&M	Operations and Maintenance
N_2	Nitrogen
NH_3	Ammonia
NO_X	Nitrogen Oxides
NPVRR	Net Present Value of Revenue Requirements
NTP	Notice to Proceed
O_2	Oxygen
OEM	Original Equipment Manufacturer
Owners	LG&E, KU, IMPA & IMEA
PA	Participation Agreement
PAC	Powdered Activated Carbon
PC	Pulverized Coal
PID	Process and Instrumentation Diagrams
PJFF	Pulse Jet Fabric Filter
PM	Particulate Matter
PM10	Sub 10 Micron Particulate Matter
PO	Purchase Order
Powergen	Powergen plc, now Powergen Limited
PPA	Purchase Power Agreements
ppm	Parts per million
PRB	Powder River Basin
psia	Pounds per square inch absolute
PSSA	Power Supply System Agreement
RFP	Request for Proposals
RH	Relative Humidity
SCPC	Super-Critical Pulverized Coal
SCR	Selective Catalytic Reduction
SO_2	Sulfur Dioxide
SO_3	Sulfur Trioxide

TC1	Trimble County Unit 1
TC2	Trimble County Unit 2
VAR	Volt-Ampere of Reactive power
VOC	Volatile Organic Compounds
WAPC	Wheelabrator Air Pollution Control, Inc.
WESP	Wet Electrostatic Precipitator
WFGD	Wet Flue Gas Desulfurization

Index of Appendices

Appendix	**Description**	**Required/ Supplemental**	**Electronic Reference**
A	Project Milestone Schedule	Supplemental	◦ AppA Milestone Schedule.pdf
B	John Voyles Testimony to the CCN	Supplemental	◦ AppB Voyles.pdf
C	Guarantee Heat Balance Schematic	Supplemental	◦ AppC Heat Balance.pdf
D	Boiler General Arrangement Drawings	Supplemental	◦ 00410-0104-31000-1001 A - Boiler Side Elevation (Section) Sp.pdf ◦ 00410-0104-31000-1002 A – Boiler Plan View (grade) AppD2.pdf ◦ 00410-0104-31000-1007 A – Boiler Plant Elevation (North) AppD.pdf
E	Preliminary Steam Cycle Process & Instrumentation Drawings	Supplemental	◦ AppE Preliminary Steam Cycle.pdf
F	Mass Balances	Supplemental	◦ AppF 1 Mass Balance.pdf ◦ AppF 2 Mass Balance.pdf
G	AQCS General Arrangement Drawings	Supplemental	◦ AppG1 AQCS.pdf ◦ AppG2 AQCS.pdf ◦ AppG3 AQCS.pdf
H	Bechtel Guarantee Sheet	Supplemental	◦ AppH Bechtel GTY Sheet.pdf
I	Trimble Co 2 Ambient Change Tax Credit Study	Supplemental	◦ AppI Ambient Change.pdf
J	WAPC Guarantee Sheet	Supplemental	◦ AppJ 2 WAPC.pdf ◦ AppJ WAPC Guarantee.pdf
K	Certificate for Convenience and Necessity Order	Required	◦ AppK CCN Order.pdf
L	Fuel Quality Specifications	Supplemental	◦ AppL Fuel Specification.pdf
M	Site Plan	Required	◦ AppM Site Plan 2.pdf ◦ AppM Site Plan.pdf

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Appendix	Description	Required/ Supplemental	Electronic Reference
N	Site Plan	Required	◦ AppN Bechtel 1.pdf ◦ AppN Bechtel 2.pdf ◦ AppN EON.pdf ◦ AppN Hitachi.pdf ◦ AppN Mitsui.pdf ◦ AppN WAPC 1.pdf ◦ AppN WAPC 2.pdf ◦ AppN WAPC 3.pdf ◦ AppN WAPC 4.pdf ◦ AppN WAPC 5.pdf
O	Burns &McDonnell Preliminary Engineering Study	Required	◦ AppO Burns McDonnell.zip
P	Air Quality Permit	Required	◦ AppP Air Permit.pdf
Q	Kentucky State Board Generation and Transmission Siting Order	Required	◦ AppQ Siting Board Order.pdf
R	Participation Agreement (LGE/KU/IMPA/IMEA)	Supplemental	◦ AppR Participation Agmt.pdf
S	Purchase Orders	Supplemental	◦ AppS 1 PO.pdf ◦ AppS 2 PO.pdf ◦ AppS 3PO.pdf
T	Trimble County Site Deeds	Required	◦ App T Deeds.pdf
U	Interconnection & Operating Agreement	Required	◦ AppU Interconnection Agmt.pdf
V	Energy Market Price Assumptions	Required	◦ AppV Plan Price Assumptions.pdf
W	Certificate for Convenience and Necessity Application	Supplemental	◦ AppW CCN Application.pdf
X	Financial Model	Required	◦ AppX Financial Model.xls
Y	E.ON US Investments Corp. Board Resolution	Supplemental	◦ AppY Brd Resolutions.pdf

Index of Appendices (continued)

Appendix	Description	Required/ Supplemental	Electronic Reference
Z	KPDES Permit	Required	◦ AppZ Waste Water Permit.pdf
AA	Testimony of Sharon L. Dodson to the KPSC for the CCN	Supplemental	◦ AppAA Dodson.pdf
BB	Independent Financial Report	Required	◦ AppBB Fitch.pdf
CC	Black and Veatch Site Assessment Rpt	Required	◦ AppCC Black and Veatch.pdf
DD	Audited Financial Statements	Required	◦ AppDD1 10K-05.pdf ◦ AppDD2 10Q-05.pdf ◦ AppDD3 10Q-04.pdf ◦ App DD4 10Q-03.pdf ◦ AppDD5 20-F.pdf ◦ AppDD 6 20-F-04.pdf ◦ AppDD7 20F-03.pdf ◦ AppDD8 EUS 1.pdf ◦ AppDD9 EUS.pdf ◦ AppDD10EUS.pdf
EE	Engineering, Procurement and Construction Agreement	Required	◦ AppEE Signed EPC.pdf ◦ AppEE Exhibits.zip

Other requested appendices (*not applicable to TC2*)

	Power Purchase or Energy Sales Agreement	Not applicable	Not applicable
	Market Study for non-power output	Not applicable	Not applicable

Project Information Memorandum

I. Summary and Introduction

- *Description of the Project*

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

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

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

Summary of Qualifying Criteria Requirements

Table 1

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

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

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

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

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

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

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

- *Financing and Ownership Structure*

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

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

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

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

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

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

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

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

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

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

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

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

II. Technology and Technical Information

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

A) Primary Equipment and Systems

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

1) Boiler / Steam Turbine

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

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

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

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

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

2) Steam Cycle

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

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

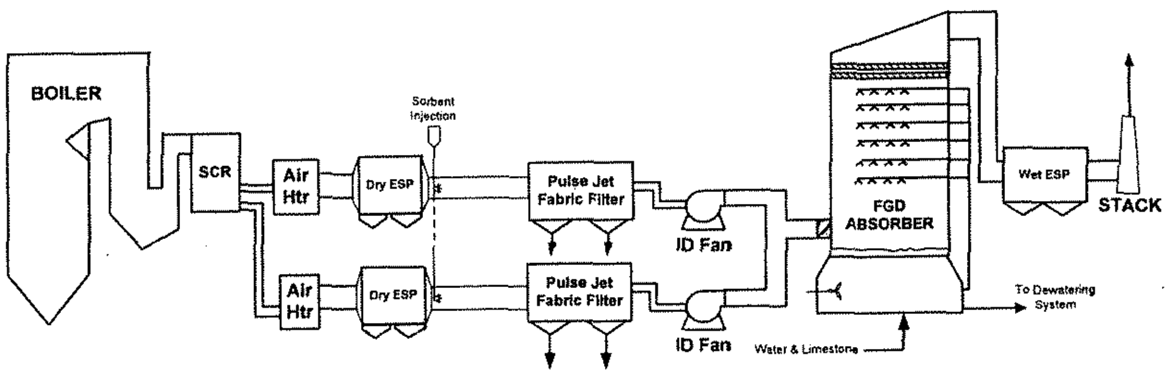
Following the turbine, the steam flows through a number of heat exchangers to transfer heat from the steam to the feedwater until it is finally condensed and returned to the system as feedwater.

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

3) Boiler Flue Gas Path

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

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



4) Air Quality Control Key Equipment

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

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

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

a) Selective Catalytic Reduction System

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

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

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

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

b) Dry Electrostatic Precipitator

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

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

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

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

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

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

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

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

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

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

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

e) Pulse Jet Fabric Filter

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

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

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

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

f) Wet Flue Gas Desulfurization

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

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

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

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

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

g) Wet Electrostatic Precipitator

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

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

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

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

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

B) Material Handling

1) Coal

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

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

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

2) Limestone

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

3) Water

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

4) Cooling Towers

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

Heat Rate Requirement

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

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

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

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

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

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

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

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

SO_2 Percent Removal Requirement

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

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

NO_x Emissions Requirement

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

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

PM Emissions Requirement

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

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

Mercury Removal Requirement

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

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

Coal Project Requirements

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

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

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

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

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

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

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

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

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

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

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

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

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

III. Priority for Integrated Gasification Combined Cycle Projects

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

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

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

IV. Site Control and Ownership

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

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

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

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

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

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

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

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

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

V. Utilization of Project Output

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

A. Costs of Electricity and Other Marketable By-Products

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

Table 2 – Costs of Electricity for TC2

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

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

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

B. Majority of Output Will Be Used for Native Load

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

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

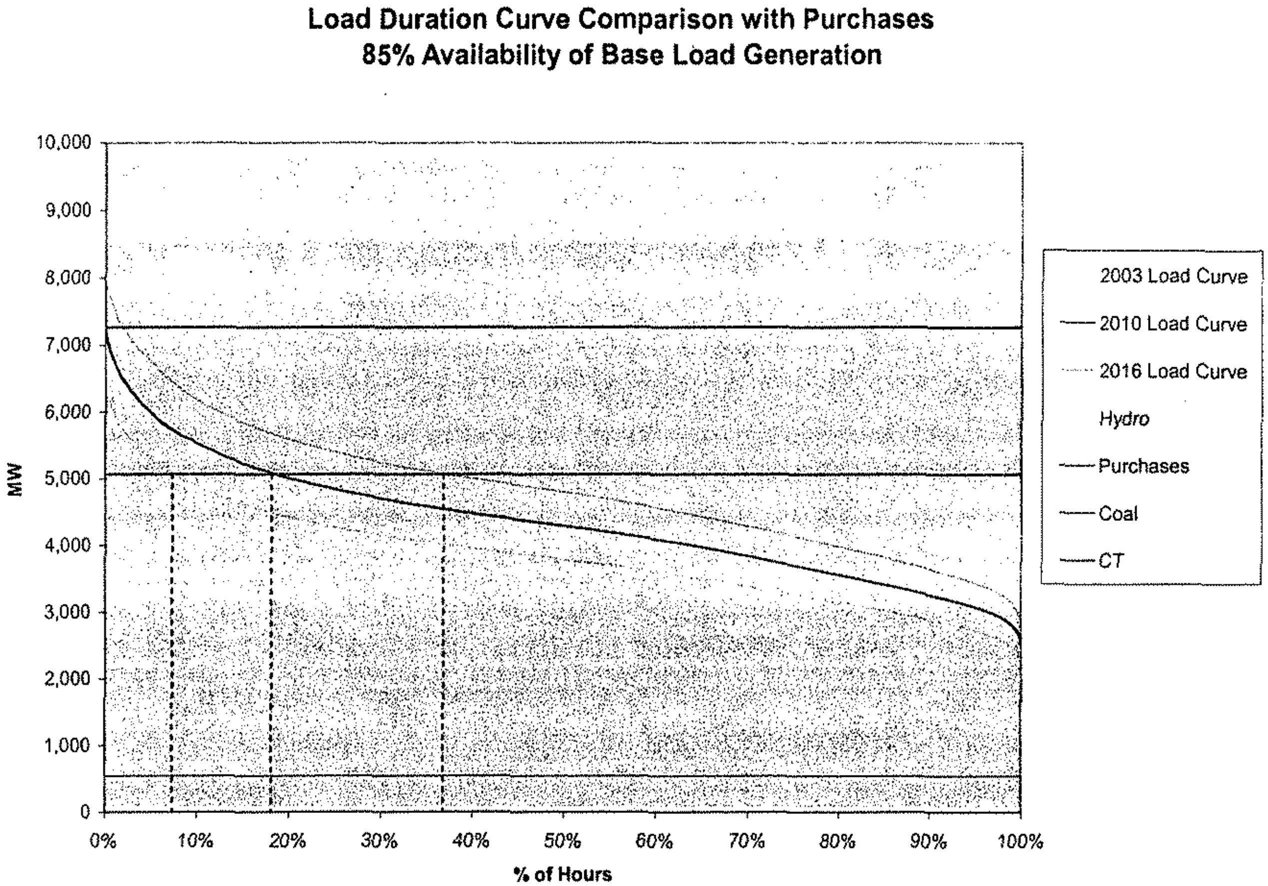
The Companies also conducted a Resource Assessment to compare the options available to meet the projected needs of their respective customers. The purpose of a Resource Assessment is to identify the least-cost option for implementing the overall resource acquisition plan. That assessment determined that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

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

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

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

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



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

Table 4 – Six Proposals Analyzed (besides TC2)

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

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

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

Table 5 – Ranking of Cases Studied in CCN

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

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

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

C. Energy Sales Arrangements

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

D. Energy Price Market Study

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

Table 6 - Market Price Assumptions for TC2

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

E. Non-Power Output Sales

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

VI. Project Economics

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

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

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

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

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

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

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

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

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

VII. Project Development and Financial Plan

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

Description of Modeling

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

Overview of the PROSYM Chronological Simulation Model

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

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

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

Unit Operation Conditions

TC2 was modeled using the following operating conditions:

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

Proforma Project Financial Projections

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

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

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

Capital Costs

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

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

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

Operations and Maintenance Costs

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

VIII. Project Contract Structure

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

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

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

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

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

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

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

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

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

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

A copy of the PA dated February 9, 2004 is provided as Appendix R.

- *Shareholders Agreement: summarize key terms and include the agreement as an appendix.*

Table 8 below contains a summary key terms contained in the PA. Appendix R contains the agreement.

Table 8

TRIMBLE 2 PARTICIPATION AGREEMENT
KEY TERMS SUMMARY

ITEM	TERM SUMMARY
Parties/Ownership	Indiana Municipal Power Agency ("IMPA") 12.88% Illinois Municipal Power Agency ("IMEA") 12.12% Collectively the Agencies LG&E and KU (Companies) 75.00%
Costs	Each party pays its pro rata portion of all TC2 costs (development, construction, operation, maintenance, retirement, etc.). All costs are prorated based on ownership except for fuel and reactant expenses which are prorated based on energy delivered. The $85 million in transmission costs are necessary to move TC2 energy to the Utilities' load. The Agencies will only pay a 25% share of the $8 million direct interconnection costs that are part of the total transmission costs.
Control	The Companies control the development, construction and operation of TC2, subject to meeting a "Good Utility Practice" standard and complying with approved budgets. The Development Budget is an exhibit to the Agreement. The Construction Budget is approved by a majority vote of the Coordination Committee (Companies 75%, Agencies 25%). Any changes to budgets are also approved by majority vote.
Development Phase Payments	The Companies accrue Development Costs until April 1, 2004. The Agencies then pay their pro rata share of accrued Development Costs plus interest plus the 2% Supervisory Fee. The Agencies make monthly payments thereafter.

TRIMBLE 2 PARTICIPATION AGREEMENT KEY TERMS SUMMARY

ITEM	TERM SUMMARY
Development Schedule	The Parties to use commercially reasonable efforts to meet project milestones: Each Party to execute Transmission Service Agreements with applicable ISO by July 1, 2004. (ii) The Companies to execute an Interconnection Agreement with applicable ISO by December 1, 2003. *(iii)* Each Party to obtain regulatory approvals by July 1, 2005. (iv) The Companies to obtain environmental permits by February 1, 2005. (v) Each Party to obtain final authorization and project funding by November 1, 2005. (vi) Construction closing December 31, 2005.
Development Phase Termination / Withdrawal	Any Party may withdraw during the Development Phase. If the Companies withdraw, the agreement is terminated, Agency payments may be refunded, development stops, and Agency option to participate in TC2 remains. If an Agency terminates, no refund of payments and Agency option to participate in TC2 ends. The Companies may continue development.
Construction Phase Termination / Withdrawal	Withdrawal during the Construction Phase is a breach. If the Companies withdraw, the construction stops and the Agencies may seek actual damages. If an Agency withdraws, the construction continues and the Companies and remaining Agency buyout the withdrawing Agency's interest at a discount after construction is completed.
Construction Budget	To be submitted 90 days prior to construction closing and approved by a majority vote of the Coordination Committee. Amendments to the Construction Budget are also by majority vote of the Coordination Committee. An Agency may elect to not participate in cost overruns in excess of the initial Construction Budget and be diluted at a discounted rate.

TRIMBLE 2 PARTICIPATION AGREEMENT KEY TERMS SUMMARY

ITEM	TERM SUMMARY
Construction Phase Payments	Agencies pay their pro rata share of Construction Costs plus the 2% Supervisory Fee monthly.
Operating Procedures	Each Party will only be entitled to use its pro rata share of any Plant Attribute (i.e., Capacity, Energy, Ramp Rate, VAR's) Any inadvertent use of any other Party's pro rata share of a Plant Attribute will be compensated in a way that complies with FERC Comparability Standards.
Assignments	Each Party has a right of first refusal and consent rights, not to be unreasonably withheld on any transfer to a non-affiliate.
Disputes	Disputes to be resolved by the: (i) Coordination Committee (ii) Senior Executives (iii) Voluntary Binding Arbitration

- *Engineering, Procurement and Construction Agreement: describe the key terms of the existing or expected EPC contract arrangement, including firm price, liquidated damages, hold-backs, performance guarantees, etc.*

The table below describes the key terms of the existing TC2 EPC Agreement. The EPC Agreement was signed on June 10, 2006.

EPC Parties: Louisville Gas & Electric Co., Kentucky Utilities Co., Indiana Municipal Power Agency and Illinois Municipal Electric Agency ("Owners") and Bechtel Power Corp. ("Bechtel").

Contract Price: Lump sum turnkey price, plus provisional sum for the Mercury and PM10 Continuous Emissions Monitors.

Performance: Net Power Output of a nominal 750 net MW and Net Plant Heat Rate of 8662 BTU/ KWh.

Schedule:

Notice to Proceed ("NTP")	June 28, 2006
Scheduled Mechanical Completion	February 15, 2010
Guaranteed Commercial ("GCOD")	June 15, 2010

Warranty: Two years on entire plant from Bechtel with extended warranties from OEM's passed through.

Security:		Letters of credit to be received by Owners upon NTP (i.e., the time that Owners authorize Bechtel to commence full construction). The letters of credit are stepped down over the course of the project in four increments and then fully released upon Final Completion (or upon completion of functional tests, if later).
Liquidated Damages:	Schedule:	If TC2 does not achieve Substantial Completion by GCOD;
	Performance:	Bechtel must correct performance if TC2 does not achieve a minimum Guaranteed Net Output or a maximum Guaranteed Net Plant Heat Rate ("Minimum Performance").
	Reliability:	Bechtel must achieve a minimum Equivalent Availability Factor ("EAF") during a 30 day reliability test.

- *Water Supply Agreement: confirm the amount, source, and cost of water supply.*

Increase maximum water withdrawal capacity from current 12,000 gal/min to 54,000 gal/min. Water source is the Ohio River at no cost.

- *Transmission interconnection agreement: explain the requirements to connect to the system and the current status of negotiations in this respect.*

All required contracts and regulatory approvals are in place for the construction of the system improvement necessary to interconnect TC2 and to move the power from TC2 to the Companies' and Agencies' customers.

The Companies are currently members of the Midwest Independent Transmission System Operator ("MISO"). An Interconnection Request #75052130 was sent to MISO in March 2002. In response MISO produced System Impact Study A-024 in May of 2003 and a Generation Interconnection Evaluation, Project G218 (MISO Queue #37356-01) in March of 2003. Both of these studies identified constraints and possible solutions to those constraints in the MISO transmission footprint and adjacent non-MISO transmission systems. After selecting from among the possible solutions identified, a MISO-prepared Facility Study Report, Project F012 (MISO OASIS # 75052130) identified the cost and schedule for required system improvements in July 2003. Subsequently MISO and the Companies entered into an Interconnection and Operating Agreement on January 27, 2004. (Included as Appendix U). The Companies acting as the Transmission Owner filed for regulatory approvals necessary to construct the required system improvements. The KPSC issued orders in September 2005 and May 2006 approving the construction of the required system improvements. The Companies are currently acquiring rights of way for the construction. All transmission construction is scheduled to be complete in the fall of 2009.

The Companies are in the regulatory process of exiting from MISO. However, such withdrawal will have no effect on the Interconnection and Operating Agreement.

IX. Permits including Environmental Authorizations

- *Provide a complete list of all federal, state, and local permits, including environmental authorizations or reviews, necessary to commence construction of the project.*

Title V, Acid Rain/NO_x Budget permits for the construction/operation of a new electrical generating unit.Permit # - V-02-043 (Revision #2) January 4, 2006. See Appendix P.

Kentucky Pollutant Discharge Elimination System ("KPDES") Permit # KY0041971 (effective 10/1/02), see Appendix Z.

- *Explain what actions have been taken to date to satisfy the required authorizations and reviews, and the status of each.*

The Title V, Acid Rain/NO_x Budget permits for the construction/operation of a new electrical generating unit was received/deemed final January 4, 2006. See Appendix P.

The Kentucky Pollutant Discharge Elimination System ("KPDES") Permit # KY0041971 expires September 30, 2007. The additional anticipated flows will be included during the renewal application in March 2007. LG&E does not anticipate significant changes to the permit as a result of TC2. See Appendix Z.

- *Provide a description of the applicant's plan to obtain and complete all necessary permits, and environmental authorizations and reviews.*

With the approved CCN from the KPSC, the Companies have obtained all necessary permits to commence construction of TC2. The appropriate permits are covered in Ms. Sharon L. Dodson's testimony to the KPSC for the CCN, see Appendix AA. Moreover, the required permits are shown in that file on pages 12 and 13, otherwise labeled Exhibit SLD-3. Additionally, any permits routinely required for construction (i.e. plumbing, building, etc.) will be obtained at the appropriate time as necessary.

The Title V, Acid Rain/NO_x Budget permits for the construction/operation of a new electrical generating unit was received/deemed final January 4, 2006. See Appendix P.

The Kentucky Pollutant Discharge Elimination System ("KPDES") Permit # KY0041971 was effective 10/1/02, see Appendix Z.

Water for TC2 will be taken from the Ohio River through existing intake structures and under existing permits.

X. Steam Turbine Purchase

- *If applicant plans to purchase a steam turbine or turbines for the project, indicate the prospective vendors for the turbine and explain the current status of purchase negotiations, and provide a timeline for negotiation and purchase with expected purchase date.*

A Purchase Order (number 25191-100-POA-MUSG-00001) has been released to Hitachi America, Ltd. for the purchase of the steam turbine. Pricing, terms and conditions and schedule have all been agreed between the parties. The Purchase Order Cover Letter for the Steam Turbine as well as the Steam Generator and the AQCS are attached in Appendix S.

XI. Project Schedule

- *Provide an overall project schedule which includes technical, business, financial, permitting and other factors to substantiate that the project will meet the 2 year project certification and 5 year placed-in-service requirement.*

Appendix A contains the TC2 Project Milestones Schedule.

APPENDICES

- *Independent Financial Report.*

See Appendix BB.

- *Copy of internal or external engineering reports.*

See Appendices I, O and CC (Black and Veatch Site Assessment Report).

- *Copy of site plan, together with evidence that applicant owns or controls a site. Examples of evidence would include a deed, or an executed contract to purchase or lease the site.*

See Appendices M and T.

- *Information supporting applicant's conclusion that the site is fully acceptable as the project site with respect to environment, coal supply, water supply, transmission interconnect, and public policy reasons.*

See Appendices M, K, P, Q, U and Z.

- *Power Purchase or Energy Sales Agreement.*

Not Applicable.

- *Energy Market Study.*

See Appendix V.

- *Market Study for non-power output.*

Not Applicable.

- *Financial Model of project.*

See Appendix X.

- *Audited financial statements for the applicant for the most recently ended three fiscal years, and the unaudited quarterly interim financial statements for the current fiscal year.*

See Appendix DD.

- *For each project contract, if no contract currently exists, provide a summary of the expected terms and conditions.*

See Appendix EE (Engineering, Procurement and Construction Agreement).

- *List of all federal, state, and local permits, including environmental authorizations or reviews, necessary to commence construction.*

See Appendices P, Z, AA.

- *If an appendix listed above is not provided, include in its place a complete explanation of the reasons for the omission.*

The project will not have a Power Purchase or Energy Sales Agreement since TC2 will generate power needed to serve native load customers.

A market study was not completed because power will be used for native load customers.

A market study for non-power output was not performed, since the Companies have not yet identified marketing opportunities for the non-power output.

Since an EPC contract has already been executed for the project, a summary for a project contract that does not exist was not applicable.

The Companies respectfully request confidential treatment of this application and all appendices contained herein, as they contain trade secrets and commercial or financial information which is exempt from disclosure under the Freedom of Information Act, 5 USC sec. 552, Subject to the Trade Secrets Act, 18 USC sec. 1905.

Signature – Kentucky Utilities Company and Louisville Gas and Electric Company

Declaration

Under penalties of perjury, I declare that I have examined this submission, including accompanying documents, and, to the best of my knowledge and belief, all of the facts contained herein are true, correct, and complete.

John N. Voyles

John N. Voyles
Vice President – Regulated Generation
June 28, 2006

e·on | U.S.

S. Bradford Rives
Chief Financial Officer

220 West Main Street
Louisville, Kentucky 40202
T (502) 627-3990
F (502) 627-2111
brad.rives@eon-us.com

September 27, 2006

Via Certified Mail

Internal Revenue Service
Attn: CC:PSI:6, Room 5313
P.O. Box 7604
Ben Franklin Station
Washington, DC 20044

Re: SECTION 48A APPLICATION FOR CERTIFICATION

Gentlemen:

Enclosed please find the completed application for advanced coal project credits which is submitted for your approval. This is a joint application of Kentucky Utilities Company and Louisville Gas and Electric Company for their Trimble Count Unit 2 project. Pursuant to Notice 2006-24, this application is being made to the Internal Revenue Service. The Taxpayers previously requested Department of Energy Certification. Under separate cover, we are also filing the Section 48A Certification Requirements.

We thank you in advance for your consideration of this application. Please feel free to contact us if you have any questions regarding the same. Please return a stamped copy of this transmittal letter for our file in the enclosed self-addressed envelope. Thank you in advance for your assistance in this matter.

Very truly yours,

SBRives

Enclosures

SECTION 48A APPLICATION FOR CERTIFICATION

Applicant Name:	Kentucky Utilities Company and Louisville Gas and Electric Company
Applicant Address:	220 West Main Street, P. O. Box 32030 Louisville Kentucky 40232
Taxpayer identification number:	Kentucky Utilities Company 61-0247570 Louisville Gas and Electric Company 61-0264150
Contact Person:	Ronald L. Miller, Director Corporate Tax, (502) 627 - 2687 Gregory J. Meiman, Senior Counsel (502) 627 - 2562 J. Scott Williams, Manager Tax Accounting, (502) 627 - 2530
Qualified advanced coal project:	Trimble County Unit 2 487 Corn Creek Road Bedford, Kentucky 40006

Table of Contents

INDEX OF ABBREVIATIONS

BACT	Best Available Control Technology
Bechtel	Bechtel Power Corporation
Btu/kWh	British Thermal Units per Kilowatt hour
Btu/Lb	British Thermal Units per Pound
CCN	Certificate of Public Convenience and Necessity
DESP	Dry Electrostatic Precipitator
DOE	Department of Energy
E.ON	E.ON AG
E.ON U.S.	E.ON U.S. LLC
EPC	Engineering, Procurement & Construction
^{o}F	Fahrenheit
Hg	Mercury
IGCC	Integrated Gasification Combined Cycle
IMEA	Illinois Municipal Electric Agency
IMPA	Indiana Municipal Power Agency
IRS	Internal Revenue Service
ISO	Independent System Operator
KPDES	Kentucky Pollutant Discharge Elimination System
KU	Kentucky Utilities Company
Lb/MMBtu	Pound per Million British thermal units
Lb/MWh	Pound per Megawatt hours
LG&E	Louisville Gas and Electric Company
MMBtu	Million British thermal units
MMBtu/hr	Million British thermal units per hour
MW	Megawatt
MWH	Megawatt Hours
NO_X	Nitrogen Oxide
PJFF	Pulse Jet Fabric Filter
PM	Particulate Matter
psia	Pounds per square inch absolute
RH	Relative Humidity
SCPC	Super-Critical Pulverized Coal
SCR	Selective Catalytic Reduction
SO_2	Sulfur Dioxide
TC1	Trimble County Unit 1
TC2	Trimble County Unit 2
WAPC	Wheelabrator Air Pollution Control, Inc.
WESP	Wet Electrostatic Precipitator
WFGD	Wet Flue Gas Desulfurization

Kentucky Utilities Company ("KU") and Louisville Gas and Electric Company ("LG&E") (referred to herein as "the Companies") submit this Section 48A Application for Certification pursuant to Section 48A of the Internal Revenue Code and the Guidelines issued by the Internal Revenue Service ("IRS") on February 21, 2006 (Notice 2006-24).[1] As required under the Guidelines, the Companies submitted an Application for Department of Energy Certification ("DOE Application") on June 28, 2006. Accordingly, the Companies request that the IRS accept the Companies' Section 48A Application for Certification and allocate to the Companies an investment tax credit of $125 million. The Companies are submitting simultaneously with this Application its Section 48A Certification Requirements. As explained in that submission, the Companies are seeking issuance of the certification because they have satisfied the requirements under Section 48A that all federal and state environmental authorizations or reviews necessary to commence construction of the project have been received and that the main steam turbine for the project has been contracted for.

Summary of the Project

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

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[1] Both KU and LG&E are operating subsidiaries of E.ON U.S. LLC ("E.ON U.S."). E.ON U.S. is ultimately owned by E.ON AG, an integrated power and gas company based in Dusseldorf, Germany. See the DOE Application, which is attached to this Application as Exhibit 1, for details regarding the parties to the project and the project itself.

[2] IMPA is a not-for-profit corporation and a political subdivision of the State of Indiana. IMPA was created in 1980 for the purpose of jointly financing, developing, owning and operating electric generation and transmission facilities appropriate to the present and projected energy needs of its participating members. IMPA sells power to its members under long-term power sales contracts. IMPA's owned and member-dedicated generating capacity is 811 megawatts. IMEA is a not-for-profit, municipal corporation and unit of local government of the State of Illinois. IMEA was created in 1984 for the purpose to jointly plan, finance, own and operate facilities for the generation and transmission of electric power to provide for the current and projected energy needs of the purchasing members. IMEA has forty members, each of which is a municipal corporation in the State of Illinois and owns and operates a municipal electric distribution system.

As part of the TC2 project, new transmission lines are needed to provide stability for the output from TC2. The new transmission lines are based on studies performed by the Companies and approved by the Midwest Independent System Operator. The Companies received a Certificate of Public Convenience and Necessity ("CCN") for the direct interconnection part of these facilities on September 8, 2005 from the Kentucky Public Service Commission. An additional CCN for transmission system upgrades was received on May 26, 2006. The additional transmission lines are a 42 mile Hardin County-Mill Creek 345 kilovolt line and a 2.55 mile Trimble County-Public Service Indiana 345 kilovolt line. Construction for part of the transmission upgrade has begun.

The estimated total cost of the project is approximately $1.25 billion. The estimated amount of qualified investment in eligible property is approximately $988 million. The amount of qualifying advanced coal project credit requested for the project is $125 million.

Attached as Exhibit 1 is a paper copy of the Department of Energy Application filed on June 28, 2006 in accordance with section 5.02 of Notice 2006-24. KU and LG&E satisfied all requirements of the Department of Energy Application.

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

Table 1 - Summary of Qualifying Criteria Requirements

Criteria	Section 48A Requirement	Trimble County Unit 2
Heat Rate	8530 Btu/kWh	8350 Btu/kWh
SO_2 percent removal	99%	99%
NO_x emissions	0.07 lbs/MMBtu	0.04 lbs/MMBtu (guaranteed) 0.05 lbs/MMBtu (permitted)
PM emissions	0.015 lbs/MMBtu	0.015 lbs/MMBtu
Hg percent removal	90%	90%
Project to power	New electric generation OR Retrofit/repower existing	New electric generation
Amount of project is electrical power	At least 50%	100%
Fuel	At least 75% coal	100% coal
Project location	Generation Unit at one site	Yes; Trimble County Station, 487 Corn Creek Rd, Bedford, KY 40006
Nameplate	At least 400 MW	Nominal 750 net MW
Project Status	Ongoing engineering activities	Approved by State agencies with permits and procurement/construction contracts in place.
Project Type	IGCC or qualifying advanced coal project	Qualifying advanced coal project

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

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

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

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

Finally TC2 will be designed to limit filterable and condensable Particulate Matter ("PM") emissions to 0.015 lbs/MMBtu. This will be accomplished by the combination of the DESP, PJFF, WFGD and WESP.

The heat rate and emission limits quoted above as design values are vendor guarantees with liquidated damages or make right requirements contained in executed purchase orders. Hitachi

American Limited will supply the steam turbine generator. Wheelabrator Air Pollution Control, Inc. ("WAPC") will supply the air quality control system and Mitsui Babcock Energy Ltd. will supply the boiler which includes the SCR. Bechtel, the engineering, procurement and construction ("EPC") contractor for TC2, will design and construct TC2 and provide the ultimate guarantee of TC2 emissions and performance to the Companies.

Description of Project Qualifications Under Section 48A

The following sections explain how TC2 will satisfy the qualification requirements of the legislation in more detail.

Heat Rate Requirement

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

With respect to site reference conditions, the Bechtel guarantee conditions of 59°F and 60% RH (which is the standard for system design) needed to be converted in order to apply the conditions contained in Section 48A(f)(2)(D) of 14.4 psia, 63°F dry bulb, 54°F wet bulb, and 55% RH. Those adjustments were made in Trimble County 2, Ambient Change, Tax Credit Study (See Exhibit 1, DOE application Appendix I). The performance data for the existing cooling tower, which was originally designed for two units but which will be enhanced in conjunction with this project, is based upon 90°F dry bulb conditions. As indicated, the guaranteed performance heat rate was first adjusted to a 90°F condition utilizing the existing cooling tower performance data. That 90°F case was then adjusted to the 54°F wet bulb criteria.

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

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

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

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

SO_2 Percent Removal Requirement

The WAPC purchase order provides for WAPC to guarantee 99% SO_2 removal from the TC2 flue gas.

NO_x Emissions Requirement

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

PM Emissions Requirement

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

Mercury Removal Requirement

The WAPC purchase order provides for WAPC to guarantee 90% Hg removal from the TC2 flue gas.

Coal Project Requirement

TC2 is a new electric generation unit and 100% of the useful output is electrical power. The Fuel Quality specifications to the project EPC contract show that 100% of the fuel for TC2 will be coal.

Site Control and Ownership

LG&E owns the approximately 2,200 acre Trimble County Station Site. On April 5, 2006, LG&E transferred an undivided ownership interest in the TC2 site (approximately 6.5 acres under TC2) to the other owners of TC2.

TC2 will be installed at an existing site in the E.ON U.S. fleet. This site has existing infrastructure for coal handling, limestone handling, water intakes, cooling tower and civil works completed.

Project Status and Permits

The project continues to progress according to the Project Milestone Schedule, which is contained in Appendix A of Exhibit 1. Purchase orders were issued to Hitachi American Limited for the turbine and WAPC for the air quality control system in April 2006. A purchase order was issued to Mitsui Babcock Energy Ltd. for the boiler in May 2006. These purchase orders have a total value of more than $300 million. Bechtel has commenced the detailed engineering for the project with their sub-suppliers and placed orders for critical pipe. Site mobilization began on July 5, 2006. Excavation of the boiler and steam turbine areas is currently in progress, as well as the relocation of balance of plant systems for TC1 that interfere with the location of TC2.

The overall Summary Schedule of TC2 Project is shown on page 23 of Mr. John Voyles' testimony as Exhibit JNV-5 in the TC2 CCN and can be seen in Appendix B of Exhibit 1. Construction of TC2 will be primarily performed through a single EPC contract that will primarily include the boiler, air pollution equipment, and turbine generating systems. The Companies expect actual construction to take approximately four years. The current milestone summary is shown in Appendix A of Exhibit 1.

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

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

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

Utilization of Project Output

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

Eligible Property

The Companies seek an investment tax credit for their investment in the eligible property of TC2. TC2 includes a steam generator and turbine, as well as the necessary pollution control equipment to enable it to qualify for the investment tax credit. In addition, eligible property also includes the necessary upgrades to the transmission system to accommodate the new facility.

Further, the Companies capitalized interest as property eligible for the investment tax credit. As explained below, the eligible property includes all elements of the project.

Section 48A of the Internal Revenue Code provides that an investment tax credit is available for "eligible property." Eligible property is defined for an integrated gasification combined cycle ("IGCC") facility as "any property which is a part of such project and is necessary for the gasification of coal, including any coal handling and gas separation equipment." For projects other than IGCC, eligible property is defined as "any property which is a part of such project."

Congress intended that the scope of "eligible property" under Section 48A be limited only with respect to IGCC facilities. "With respect to IGCC projects, the conference agreement narrows the definition of credit-eligible investments to include only investments in property associated with the gasification of coal, including any coal handling and gas separation equipment. Thus, investments in equipment that could operate by drawing fuel directly from a natural gas pipeline do not qualify for the credit." *Description and Technical Explanation of the Conference Agreement of H.R. 6, Title XIII, "Energy Tax Incentives Act of 2005,"* p. 36 (July 27, 2005). For projects other than IGCC, no such limits were included in the legislation, and Congress spoke to no limits in the legislative history of the provision.

Under Section 48A, Congress intended that all property that is part of an advanced coal project other than IGCC be included within the scope of eligible property, including transmission facilities. In this manner, the language is broader than the investment tax credit language for either solar or geothermal facilities. In terms of solar energy equipment, the ITC is available for "equipment which uses solar energy to *generate* electricity..." *Id.* at 48(a)(3)(A)(i) (*emphasis added*). For geothermal, the ITC is available for "equipment used to produce, distribute, or use energy derived from a geothermal deposit,... but only, in the case of electricity generated by geothermal power, up to (but not including) the electrical transmission stage." *Id.* at 48(a)(3)(A)(iii). Congress limited the ITC for solar facilities to equipment used to <u>generate</u> electricity, while for geothermal facilities, transmission facilities are specifically excluded from the scope of eligible property. On the other hand, with respect to advanced coal facilities other than IGCC, Section 48A neither limits the scope of eligible property to equipment used to generate electricity nor does it specifically exclude transmission facilities. In fact, unlike both solar and geothermal facilities, there are no limitations regarding eligible property for advanced coal projects other than IGCC projects.[3]

[3] The use of the phrase "any property which is a part of such project" in prior investment tax credit language further supports the inclusion of transmission facilities within the scope of eligible property. The Tax Reform Act of 1986 repealed an existing investment tax credit, but allowed its continuation for a brief period for "transition property," which was defined to include "<u>property which is part of a project</u> which is certified by the Federal Energy Regulatory Commission before March 2, 1986, as a qualifying facility for purposes of the Public Utility Regulatory Policies Act of 1978." *Tax Reform Act of 1986,* No. 99-514, 100 Stat. 2085 (October 22, 1986), Sections 204(a)(2)(A); 211(a). The Federal Energy Regulatory Commission determined that a qualifying facility included transmission facilities. *Clarion Power Company,* 39 FERC ¶ 61,317 (June 18, 1987). And in Private Letter Rulings, the IRS determined that "property which is part of a project" under Section 204(a)(2)(A) of the Tax Reform Act of 1986 included transmission facilities. *See, Private Letter Ruling 8947034,* 1989 PLR LEXIS 2729 (August 28, 1989); *Private Letter Ruling 8843017,* 1988 PLR LEXIS 2336 (July 29, 1988).

The expected capital costs for TC2 construction in its entirety is approximately $1.25 billion. The Capital and Transmission costs in total have not changed from the DOE Application but the spending per year has changed due to new estimates. Also, capitalized interest has been added to the project costs since the DOE Application was filed. Since 25% of the project is owned by IMEA and IMPA, the total construction costs to the Companies will be 75% of the total costs of the facility. All of the expected capital costs of the advanced coal facility, TC2, will qualify under Section 48A as eligible property. The Companies' portion of the costs is shown in Table 2 and Table 3 as follows.

Table 2 – TC2 Costs (75% ownership only)
(Nominal $000s)

Year	Capital	Capitalized Interest	Transmission	Total
2005	7,900	0	1,000	8,900
2006	102,500	4,000	5,000	111,500
2007	305,400	15,000	15,000	335,400
2008	288,200	30,000	27,000	345,200
2009	83,000	41,000	35,000	159,000
2010	5,000	22,000	1,000	28,000
Grand Totals	**792,000**	**112,000**	**84,000**	**988,000**

Table 3 - Breakdown of Eligible Property

Steam Generator	$108,800,000
Steam Turbine	47,000,000
Air Quality Control System Package	220,200,000
SCR	24,400,000
Ash Handling	18,400,000
Other Pollution Control Costs	42,000,000
Balance of Project and Construction	517,200,000
Development Costs	15,500,000
Total EPC contract costs	$993,500,000
Costs_outside of EPC contract	62,500,000
Total Capital Project Budget	$1,056,000,000
Less IMEA/IMPA 25% ownership	(264,000,000)
Subtotal	$792,000,000
Transmission	84,000,000
Capitalized Interest	112,000,000
Total Capital	$988,000,000
Total eligible plant	$988 000,000
Tax credit percentage	x 15%
Tax credit calculated	$148,200,000
Tax credit applied for	$125,000,000

Bechtel is the engineering, procurement and construction contractor for TC2 and will design and construct TC2 and ultimately provide the guarantee of TC2 emissions and performance to the Companies. Individual component costs to construct TC2 are included in Bechtel's "Balance of Project and Construction" line item above. For total cost of EPC contract see Exhibit 1 Appendix EE Article 8.1(page 73). Also, for a detailed breakdown of EPC contract costs see Exhibit 1 – Sub Exhibit X of Appendix EE.

See Exhibit 2 for calculation of capitalized interest and Exhibit 3 for transmission project costs.

Ratio of Total Nameplate Capacity to Requested Allocation

TC2 would provide a high ratio of total nameplate generating capacity to requested credit allocation, as reflected in the following calculation:

Total credit applied for	$125,000,000
Nameplate Capacity (MW)	750
Tax Credit per MW Nameplate capacity	$166,667

EXHIBITS

Exhibit 1 - Application for Department of Energy Certification
Exhibit 2 - Calculation of Capitalized Interest
Exhibit 3 - Transmission Project Costs
Exhibit 4 - Power of Attorney and Declaration of Representative, Form 2848

The Companies respectfully request confidential treatment of this application and all appendices contained herein, as they contain trade secrets and commercial or financial information which is exempt from disclosure under the Freedom of Information Act, 5 USC sec. 552, Subject to the Trade Secrets Act, 18 USC sec. 1905.

Signature – Kentucky Utilities Company and Louisville Gas and Electric Company

Declaration

Under penalties of perjury, I declare that I have examined this submission, including accompanying documents, and, to the best of my knowledge and belief, all of the facts contained herein are true, correct, and complete.

S. Bradford Rives
Chief Financial Officer
September 27, 2006

Exhibit 2
CALCULATION OF CAPITALIZED INTEREST

The Companies respectfully request confidential treatment of this exhibit, as it contains trade secrets and commercial or financial information which is exempt from disclosure under the Freedom of Information Act, 5 USC sec. 552, Subject to the Trade Secrets Act, 18 USC sec. 1905.

Kentucky Utilities Company
Louisville Gas & Electric Company
Trimble County 2 Project
Capitalized Interest (Projected)
2006 - 2010

	2005	2006	2007	2008	2009	2010	
Average CWIP							
Q1	2,225,000	35,775,000	196,500,000	515,600,000	781,500,000	873,000,000	
Q2	4,450,000	62,650,000	276,600,000	594,400,000	811,000,000	876,000,000	
Q3	6,675,000	89,525,000	356,700,000	673,200,000	840,500,000	-	
Q4	8,900,000	116,400,000	436,800,000	752,000,000	870,000,000	-	
Total Average CWIP	5,562,500	76,087,500	316,650,000	633,800,000	825,750,000	437,250,000	
KU (81%)	4,505,625	61,630,875	256,486,500	513,378,000	668,857,500	354,172,500	
Embedded Cost of Capital (Long-term)	4.010%	4.796%	4.759%	4.870%	4.972%	5.079%	
Capitalized Interest	180,676	2,955,817	12,206,193	25,001,509	33,255,595	17,988,421	
LGE (19%)	1,056,875	14,456,625	60,163,500	120,422,000	156,892,500	83,077,500	
Embedded Cost of Capital (Long-term)	4.020%	4.408%	4.550%	4.660%	4.885%	5.052%	
Capitalized Interest	42,486	637,248	2,737,439	5,611,665	7,664,199	4,197,075	
Total Capitalized Interest	223,162	3,593,065	14,943,632	30,613,174	40,919,794	22,185,497	**112,478,322**

Exhibit 3
TRANSMISSION COSTS

The Companies respectfully request confidential treatment of this exhibit, as it contains trade secrets and commercial or financial information which is exempt from disclosure under the Freedom of Information Act, 5 USC sec. 552, Subject to the Trade Secrets Act, 18 USC sec. 1905.

Summary of costs per estimated Authorization for Investment Proposals

Project #	Amount
121636	$44,745,749
121639	12,993,988
121640	6,240,000
Other Transmission Costs	20,020,263
Total	$84,000,000

AUTHORIZATION FOR INVESTMENT PROPOSAL

[X] Original
[ ] Revised

[ ] LG&E Energy Services Co. [ ] Louisville Gas & Electric Co. [X] Kentucky Utilities Company
[ ] LG&E Energy Marketing [ ] Western Kentucky Energy [ ] LG&E Power Inc. [ ] Other:

Name of Project:	TC2 E. Ft. Knox - HC 345kv				
Date Requested: 8/7/2006		Project Number: 121636		Related Project Numbers:	121639
Budgeted [1]: Y [x] N [ ]		If unbudgeted, list alternate budget ref. Number(s) [1]:			
Expected Start Date [2]: 5/30/2006		Expected In-service Date [2]: 1/7/2010		Expected Completion Date [2]:	12/31/2010
AIP Prepared by: Ronnie Bradford			Phone: 502-627-3167		
Project Manager: Ronnie Bradford			Phone: 502-627-3167		

Product Code [3]	Resp. Center [4]	Location # [5]	OBU Name [6]	Environmental Code [7]	Env. Category [7]
121	015870	5200	Transmission Lines		

REASONS AND DETAILED DESCRIPTION OF PROJECT
(include sketch no. if applicable)

Mill Creek - Hardin County 345KV, East Fort Knox property boundary - Hardin County Sub.

On May 26, 2006, the Kentucky Public Service Commission granted LG&E and KU a Certificate of Public Convenience and Necessity, case number 2005-00467, to construct and operate the proposed 42.03 mile Hardin Co. - Mill Creek 345 KV transmission line. The proposed transmission line is necessary to provide stability for the output from the proposed 750 MW Trimble County Unit II (TC2) Expansion. The need for the proposed transmission line was based on studies performed by EON and validated by the Midwest Independent Transmission System Operator, Inc. (MISO).

Investment: Install 32.7 miles of 6 - 954 ACSR 45/7 conductor, 32.7 miles of 2 - 7 NO 8AW static wires in the E. Fort Knox - Hardin Co. section of the Mill Creek - Hardin Co. 345kv line. The 345KV line will be constructed with lattice steel towers, two pole steel "H" frame and single pole double circuit steel structures in this section. Approx 8.25 miles of the 32.7 miles of line, will be constructed as double circuit with existing 138kv lines.

Retirement: Remove 4.49 miles of 3- 795 ACSR 26/7 conductor, 4.49 miles of 2-7 No. 8 ALWD in the Hardin Co--Hardinsburg 138 kV line.

Costs	Capital Investment	Cost of Removal/Retirement	Capital Cost Subtotal [8]	Initial O&M Cost [9]	Lifetime Maintenance Cost [9]	O&M Cost Subtotal	TOTAL INVESTMENT
Company Labor	1,931,308		1,931,308				1,931,308
Contract Labor	18,750,805	158,907	18,909,712				18,909,712
Materials	13,198,771		13,198,771				13,198,771
Rights of Way	5,203,614		5,203,614				5,203,614
Other (Describe)			-				-
Less Salvage							-
Local Engineering [10]	5,502,344		5,502,344				5,502,344
Subtotal	44,586,842	158,907	44,745,749				44,745,749
Contr. In Aid of Constr.(CIAC) [11]			-				-
Net Expenditures	44,586,842	158,907	44,745,749				44,745,749

Checked by	Date	Checked by	Date	Sketch No.

Signature Required (Based on CAPITAL COST SUBTOTAL COLUMN) [8]:

	Authorized by	Name	Signature	Date
1.	Supervisor/Team Leader (Non IT and IT up to $25k)	W. Alan Strunk	Alan Strunk	8-21-06
2.	*Director Right of Way* (Non IT >$100k up to $300k; IT >$50k up to $100k)	Kathleen A. Slay	Kathleen Slay	8/22/06
3.	Manager (Non IT >$25k up to $100k; IT >$25k up to $50k)	J. Nate Mullins	Nate Mullins	8-22-06
4.	*Director* (Non IT >$100k up to $300k; IT >$50k up to $100k)	Mark S. Johnson		
5.	OBU Budget Coordinator [13]	Elaine C Welch	Elaine C. Welch	8/22/06
6.	Financial Planning (Non-IT and IT>$300k; all unbudgeted projects; all Development Proposals)[14] or *Investment Committee Coordinator (Non-IT >$1.0M; IT >$500k; Development >$500k* [15]			
7.	Vice President (Non IT >$300k up to $750k; IT >$100k up to $200k; Development up to $200k)			
8.	Senior Officer (*Non IT >$750k up to $1.0M; IT >$200k up to $500k;* Development >$200k up to $500k)	Paul W. Thompson		
9.	CFO (Non IT >$1.0M; IT >$500k; Development >$500k) [15]			
10.	*CEO (Non IT >$1.0M up to €25.0M; IT >$500k up to €25.0M;* Development >$500k up to €25.0M) [16]			
11.	E.On Board (Non IT, IT, and Development > €25.0M)			
12.	Information Technology [16]			
13.	Property Accounting (including budget check)			

NOTE: AIP Page 2 & 3 must be completed and attached before approval of any project.

AUTHORIZATION FOR INVESTMENT PROPOSAL

[X] Original
[ ] Revised

[ ] LG&E Energy Services Co. [X] Louisville Gas & Electric Co. [ ] Kentucky Utilities Company
[ ] LG&E Energy Marketing [ ] Western Kentucky Energy [ ] LG&E Power Inc. [ ] Other:

Name of Project:	TC2 MC - East Ft. Knox 345kv line		
Date Requested: 8/7/2006	Project Number: 121638	Related Project Numbers: 121638	
Budgeted [1]: Y [X] N [ ]	If unbudgeted, list alternate budget ref. Number(s) [1]:		
Expected Start Date [2]: 5/30/2006	Expected In-service Date [2]: 1/7/2010	Expected Completion Date [2]: 12/31/2010	
AIP Prepared by: Ronnie Bradford		Phone: 502-627-3167	
Project Manager: Ronnie Bradford		Phone: 502-627-3167	

Product Code [3]	Resp. Center [4]	Location # [5]	OBU Name [6]	Environmental Code [7]	Env. Category [7]
121	003070	5200	Transmission Lines		

REASONS AND DETAILED DESCRIPTION OF PROJECT
(Include sketch no. if applicable)

Mill Creek - Hardin County 345KV. Mill Creek - East Fort Knox property boundary.

On May 26, 2006.the Kentucky Public Service Commission granted LG&E and KU a Certificate of Public Convenience and Necessity, case number 2005-00467, to construct and operate the proposed 42.03 mile Hardin Co-Mill Creek 345 KV transmission line. The proposed transmission line is necessary to provide stability for the output from the proposed 750 MW Trimble County Unit II (TC2) Expansion. The need for the proposed transmission line was based on studies performed by EON and validated by the Midwest Independent Transmission System Operator, INC. (MISO).

Investment: Install 9.33 miles of 6 - 954 ACSR 45/7 conductor, 9.33 miles of 2 - 7 NO 8AW static wires in the Mill Creek - E. Fort Knox section of the Mill Creek - Hardin Co. 345kv line. The line will be constructed with lattice steel towers and two pole steel "H" structures in this section.

Retirement: Remove 2.62 miles of 3 - 397 ACSR 26/7 conductor, 2.62 miles of 1 - 7/16" HSS static, 2.62 miles of 1 - 64mm2 OPGW, in the Tip Top - Cloverport 138KV circuit 3851 transmission line.

Costs	Capital Investment	Cost of Removal/Retirement	Capital Cost Subtotal [8]	Initial O&M Cost [9]	Lifetime Maintenance Cost [9]	O&M Cost Subtotal	TOTAL INVESTMENT
Company Labor	551,044		551,044				551,044
Contract Labor	5,489,833	92,520	5,582,353				5,582,353
Materials	3,769,803		3,769,803				3,769,803
Rights of Way	1,506,673		1,506,673				1,506,673
Other (Describe)			-				-
Less Salvage			-				-
Local Engineering [10]	1,584,115		1,584,115				1,584,115
Subtotal	12,901,468	92,520	12,993,988				12,993,988
Contr. In Aid of Constr.(CIAC) [11]			-				-
Net Expenditures	12,901,468	92,520	12,993,988				12,993,988

Checked by	Date	Checked by	Date	Sketch No.

Signature Required (Based on CAPITAL COST SUBTOTAL COLUMN) [8]:

	Authorized by	Name	Signature	Date
1.	Supervisor/Team Leader (Non IT and IT up to $25k)	W. Alan Strunk	Alan Strunk	8-21-06
2.	Director Right of Way (Non IT >$100k up to $300k; IT >$50k up to $100	Kathleen A. Slay	Kathleen Slay	8/22/06
3.	Manager (Non IT >$25k up to $100k; IT >$25k up to $50k)	J. Nate Mullins	Nate Mullins	8-22-06
4.	Director (Non IT >$100k up to $300k; IT >$50k up to $100k)	Mark S. Johnson		
5.	OBU Budget Coordinator [13]	Elaine C. Welsh	Elaine C. Welsh	8/22/06
6.	Financial Planning (Non-IT and IT>$300k; all unbudgeted projects; all Development Proposals)[14] or Investment Committee Coordinator (Non-IT >$1.0M; IT >$500k; Development >$500k [15]			
7.	Vice President (Non IT >$300k up to $750k; IT >$100k up to $200k; Development up to $200k)			
8.	Senior Officer (Non IT >$750k up to $1.0M; IT >$200k up to $500k; Development >$200k up to $500k)	Paul W. Thompson		
9.	CFO (Non IT >$1.0M; IT >$500k; Development >$500k) [15]			
10.	CEO (Non IT >$1.0M up to €25.0M; IT >$500k up to €25.0M; Development >$500k up to €25.0M) [15]			
11.	E.On Board (Non IT, IT, and Development > €25.0M)			
12.	Information Technology [16]			
13.	Property Accounting (including budget check)			

NOTE: AIP Page 2 & 3 must be completed and attached before approval of any project.

AUTHORIZATION FOR INVESTMENT PROPOSAL

[X] Original
[ ] Revised

[ ] LG&E Energy Services Co. [X] Louisville Gas & Electric Co. [ ] Kentucky Utilities Company
[ ] LG&E Energy Marketing [ ] Western Kentucky Energy [ ] LG&E Power Inc. [ ] Other:

Name of Project:	TC2 TC - PSI 345kv line		
Date Requested: 8/7/2006	Project Number: 121640	Related Project Numbers:	
Budgeted [1]: Y [x] N [ ]	If unbudgeted, list alternate budget ref. Number(s) [1]:		
Expected Start Date [2]: 5/30/2006	Expected In-service Date [2]: 12/31/2007	Expected Completion Date [2]: 3/5/2008	
AIP Prepared by: Gary R. King		Phone: 859-367-5641	
Project Manager: Gary R. King		Phone: 859-367-5641	

Product Code [3]	Resp. Center [4]	Location # [5]	OBU Name [6]	Environmental Code [7]	Env. Category [7]
121	003070	5200	Transmission Lines		

REASONS AND DETAILED DESCRIPTION OF PROJECT
(Include sketch no. if applicable)

On September 8, 2005, the Kentucky Public Service Commission granted LG&E a Certificate of Public Convenience and Necessity, case number 2005-00155 to construct and operate the proposed 2.56 mile Trimble County - PSI 345 KV transmission line. The proposed transmission line is necessary to provide stability for the output from the proposed 750 MW Trimble County Unit II (TC2) Expansion. The need for the proposed transmission line was based on studies performed by EON and validated by the Midwest Independent Transmission System Operator, Inc. (MISO). A total Contribution in Aid of Construction for twenty-five percent of the actual project costs incurred will be provided by Indiana Municipal Power Agency (IMPA) and Illinois Municipal Electric Agency (IMEA) per Participation Agreement dated, February 9, 2004.

Investment: Install 4- 150' steel pole, 1- 160: steel pole, 2- River Crossing lattice tower, 2- D type lattice tower, 1- TAD type lattice tower, 4- HT type lattice tower, 2058- 10" porcelain bell insulators (40k), 60- bundled conductor DE assembly, 15- bundled conductor Susp. assembly, 2.55 mile of 12- 954 ACSR 54/7 cardinal conductor, 2.55 miles of 2- 7 no. 8 shield wire and associated hardware and material in the Trimble Co. - PSI double circuit 345kv line.

Costs	Capital Investment	Cost of Removal/Retirement	Capital Cost Subtotal [8]	Initial O&M Cost [9]	Lifetime Maintenance Cost [9]	O&M Cost Subtotal	TOTAL INVESTMENT
Company Labor	525,000	-	525,000	-		-	525,000
Contract Labor	2,737,952		2,737,952			-	2,737,952
Materials	2,638,474		2,638,474			-	2,638,474
Rights of Way	666,304		666,304			-	666,304
Other (Describe)	115,000		115,000			-	115,000
Less Salvage			-			-	-
Local Engineering [10]	1,637,270	-	1,637,270			-	1,637,270
Subtotal	8,320,000	-	8,320,000	-	-	-	8,320,000
Contr. In Aid of Constr.(CIAC) [11]	2,080,000		2,080,000			-	2,080,000
Net Expenditures	6,240,000	-	6,240,000	-	-	-	6,240,000

Checked by	Date	Checked by	Date	Sketch No.

Signature Required (Based on CAPITAL COST SUBTOTAL COLUMN) [8]:

	Authorized by	Name	Signature	Date
1.	Supervisor/Team Leader (Non IT and IT up to $25k)	W. Alan Strunk	Alan Strunk	8-21-06
2.	Director Right of Way (Non IT >$100k up to $300k; IT >$50k up to $100k)	Kathleen A. Slay	Kathleen Slay	8/22/06
3.	Manager (Non IT >$25k up to $100k; IT >$25k up to $50k)	J. Nate Mullins	J. Nate Mullins	8-22-06
4.	Director (Non IT >$100k up to $300k; IT >$50k up to $100k)	Mark S. Johnson		
5.	OBU Budget Coordinator [13]	Elaine C. Webb	Elaine C. Webb	8/22/06
6.	Financial Planning (Non-IT and IT>$300k; all unbudgeted projects; all Development Proposals)[14] or Investment Committee Coordinator (Non-IT >$1.0M; IT >$500k; Development >$500k [15]			
7.	Vice President (Non IT >$300k up to $750k; IT >$100k up to $200k; Development up to $200k)			
8.	Senior Officer (Non IT >$750k up to $1.0M; IT >$200k up to $500k; Development >$200k up to $500k)	Paul W. Thompson		
9.	CFO (Non IT >$1.0M; IT >$500k; Development >$500k) [15]			
10.	CEO (Non IT >$1.0M up to €25.0M; IT >$500k up to €25.0M; Development >$500k up to €25.0M) [15]			
11.	E.On Board (Non IT, IT, and Development > €25.0M)			
12.	Information Technology [16]			
13.	Property Accounting (Including budget check)			

NOTE: AIP Page 2 & 3 must be completed and attached before approval of any project.

Effective 04/21/2006

Exhibit 4
POWER OF ATTORNEY – FORM 2848

Ronald L. Miller, CPA
Director, Corporate Tax

220 West Main Street
P.O. Box 32030
Louisville, KY 40232
T 502-627-2687
P 502-627-2669
ron.miller@eon-us.com

September 5, 2006

VIA Fax 703-605-1905

Mr. Douglas Kim, CC:PSI:6
Internal Revenue Service
P.O. Box 7604
Ben Franklin Station
Washington, DC 20044

Dear Mr. Kim:

In response to Kathleen Reed's August 24, 2006 letter (copy attached), enclosed please find a completed Form 2848, Power of Attorney and Declaration of Representative, for both Louisville Gas and Electric Company and Kentucky Utilities Company in connection with our Section 48A Application.

As clarification, please note that the copy of our June 28, 2006 Department of Energy application provided to the Internal Revenue Service does not represent our IRS application. The IRS application and related Sec. 48A Certification will be filed prior to October 2, 2006 deadline.

Please let me know if you have any questions regarding the attached or if there is anything else you need in connection with this filing.

Sincerely,

Ron Miller

Form **2848**
(Rev. March 2004)
Department of the Treasury
Internal Revenue Service

Power of Attorney and Declaration of Representative

▶ Type or print. ▶ See the separate instructions.

OMB No. 1545-0150

For IRS Use Only
Received by:
Name
Telephone
Function
Date

Part I **Power of Attorney**

Caution: *Form 2848 will not be honored for any purpose other than representation before the IRS.*

1 Taxpayer information. *Taxpayer(s) must sign and date this form on page 2, line 9.*

Taxpayer name(s) and address	Social security number(s)	Employer identification number
Kentucky Utilities Company 220 West Main Street P O. Box 32030 Louisville, KY 40232		61-0247570
	Daytime telephone number (502) 627-2687	Plan number (if applicable)

hereby appoint(s) the following representative(s) as attorney(s)-in-fact:

2 Representative(s) must sign and date this form on page 2, Part II.

Name and address	
Ronald L. Miller, Director Corporate Tax 220 West Main Street, P.O. Box 32030 Louisville, KY 40232	CAF No. Telephone No. (502) 627-2687 Fax No. (502) 627-2669 Check if new: Address ☐ Telephone No. ☐ Fax No. ☐
Gregory J. Meiman, Senior Counsel 220 West Main Street, P.O. Box 32030 Louisville, KY 40232	CAF No. Telephone No. (502) 627-2562 Fax No. (502) 217-2275 Check if new: Address ☐ Telephone No. ☐ Fax No. ☐
J. Scott Williams, Manager Tax Accounting 220 West Main Street, P.O. Box 32030 Louisville, KY 40232	CAF No. Telephone No. (502) 627-2530 Fax No. (502) 627-2669 Check if new: Address ☐ Telephone No. ☐ Fax No. ☐

to represent the taxpayer(s) before the Internal Revenue Service for the following tax matters:

3 Tax matters

Type of Tax (Income, Employment, Excise, etc.) or Civil Penalty (see the instructions for line 3)	Tax Form Number (1040, 941, 720, etc.)	Year(s) or Period(s) (see the instructions for line 3)
Tax matters in connection with the application for	Form 1120	2006 to 2010
Advanced Coal Project Tax Credits under Section 48A		

4 Specific use not recorded on Centralized Authorization File (CAF). If the power of attorney is for a specific use not recorded on CAF, check this box. See the instructions for **Line 4. Specific uses not recorded on CAF.** . . . . ▶ ☒

5 Acts authorized. The representatives are authorized to receive and inspect confidential tax information and to perform any and all acts that I (we) can perform with respect to the tax matters described on line 3, for example, the authority to sign any agreements, consents, or other documents. The authority does not include the power to receive refund checks (see line 6 below), the power to substitute another representative, the power to sign certain returns, or the power to execute a request for disclosure of tax returns or return information to a third party. See the line 5 instructions for more information.

Exceptions. An unenrolled return preparer cannot sign any document for a taxpayer and may only represent taxpayers in limited situations. See **Unenrolled Return Preparer** on page 2 of the instructions. An enrolled actuary may only represent taxpayers to the extent provided in section 10.3(d) of Circular 230. See the line 5 instructions for restrictions on tax matters partners.

List any specific additions or deletions to the acts otherwise authorized in this power of attorney:

6 Receipt of refund checks. If you want to authorize a representative named on line 2 to receive, **BUT NOT TO ENDORSE OR CASH** refund checks, *initial here* ____________ and list the name of that representative below.

Name of representative to receive refund check(s) ▶

For Privacy Act and Paperwork Reduction Notice, see page 4 of the instructions.

7 **Notices and communications.** Original notices and other written communications will be sent to you and a copy to the first representative listed on line 2.

a If you also want the second representative listed to receive a copy of notices and communications, check this box ▶ ☐

b If you do not want any notices or communications sent to your representative(s), check this box ▶ ☐

8 **Retention/revocation of prior power(s) of attorney.** The filing of this power of attorney automatically revokes all earlier power(s) of attorney on file with the Internal Revenue Service for the same tax matters and years or periods covered by this document. If you **do not** want to revoke a prior power of attorney, check here ▶ ☐

YOU MUST ATTACH A COPY OF ANY POWER OF ATTORNEY YOU WANT TO REMAIN IN EFFECT.

9 **Signature of taxpayer(s).** If a tax matter concerns a joint return, **both** husband and wife must sign if joint representation is requested, otherwise, see the instructions. If signed by a corporate officer, partner, guardian, tax matters partner, executor, receiver, administrator, or trustee on behalf of the taxpayer, I certify that I have the authority to execute this form on behalf of the taxpayer.

▶ **IF NOT SIGNED AND DATED, THIS POWER OF ATTORNEY WILL BE RETURNED.**

Signature	Date	Title (if applicable)
S Rives	9/5/2006	Chief Financial Officer

Print Name	PIN Number	Print name of taxpayer from line 1 if other than individual
S. Bradford Rives		Kentucky Utilities Company

Signature	Date	Title (if applicable)

Print Name	PIN Number

Part II **Declaration of Representative**

Caution: *Students with a special order to represent taxpayers in Qualified Low Income Taxpayer Clinics or the Student Tax Clinic Program, see the instructions for Part II.*

Under penalties of perjury, I declare that:

- I am not currently under suspension or disbarment from practice before the Internal Revenue Service;
- I am aware of regulations contained in Treasury Department Circular No. 230 (31 CFR, Part 10), as amended, concerning the practice of attorneys, certified public accountants, enrolled agents, enrolled actuaries, and others;
- I am authorized to represent the taxpayer(s) identified in Part I for the tax matter(s) specified there; and
- I am one of the following:

a Attorney—*a member in good standing of the bar of the highest court of the jurisdiction shown below.*

b Certified Public Accountant—*duly qualified to practice as a certified public accountant in the jurisdiction shown below.*

c Enrolled Agent—*enrolled as an agent under the requirements of Treasury Department Circular No. 230.*

d Officer—*a bona fide officer of the taxpayer's organization.*

e Full-Time Employee—*a full-time employee of the taxpayer.*

f Family Member—*a member of the taxpayer's immediate family (i.e., spouse, parent, child, brother, or sister).*

g Enrolled Actuary—*enrolled as an actuary by the Joint Board for the Enrollment of Actuaries under 29 U.S.C. 1242 (the authority to practice before the Service is limited by section 10.3(d) of Treasury Department Circular No. 230).*

h Unenrolled Return Preparer—*the authority to practice before the Internal Revenue Service is limited by Treasury Department Circular No. 230, section 10.7(c)(1)(viii). You must have prepared the return in question and the return must be under examination by the IRS. See* **Unenrolled Return Preparer** *on page 2 of the instructions.*

▶ **IF THIS DECLARATION OF REPRESENTATIVE IS NOT SIGNED AND DATED, THE POWER OF ATTORNEY WILL BE RETURNED.** See the Part II instructions.

Designation—Insert above letter (a-h)	Jurisdiction (state) or identification	Signature	Date
b,e	KY	[illegible]	9/5/2006
a,b,e	KY		9.5.2006
b,e	KY	[illegible]	9/5/2006

Form 2848
(Rev. March 2004)
Department of the Treasury
Internal Revenue Service

Power of Attorney and Declaration of Representative

▶ Type or print. ▶ See the separate instructions.

OMB No. 1545-0150
For IRS Use Only
Received by:
Name
Telephone
Function
Date

Part I **Power of Attorney**

Caution: *Form 2848 will not be honored for any purpose other than representation before the IRS.*

1 Taxpayer information. Taxpayer(s) must sign and date this form on page 2, line 9.

Taxpayer name(s) and address	Social security number(s)	Employer identification number
Louisville Gas and Electric Company 220 West Main Street P.O. Box 32030 Louisville, KY 40232		61-0264150
	Daytime telephone number (502) 627-2687	Plan number (if applicable)

hereby appoint(s) the following representative(s) as attorney(s)-in-fact:

2 Representative(s) must sign and date this form on page 2, Part II.

Name and address	
Ronald L. Miller, Director Corporate Tax 220 West Main Street, P.O. Box 32030 Louisville, KY 40232	CAF No. Telephone No. (502) 627-2687 Fax No. (502) 627-2669 Check if new: Address ☐ Telephone No. ☐ Fax No. ☐
Gregory J. Meiman, Senior Counsel 220 West Main Street, P.O. Box 32030 Louisville, KY 40232	CAF No. Telephone No. (502) 627-2562 Fax No. (502) 217-2275 Check if new: Address ☐ Telephone No. ☐ Fax No. ☐
J. Scott Williams, Manager Tax Accounting 220 West Main Street, P.O. Box 32030 Louisville, KY 40232	CAF No. Telephone No. (502) 627-2530 Fax No. (502) 627-2669 Check if new: Address ☐ Telephone No. ☐ Fax No. ☐

to represent the taxpayer(s) before the Internal Revenue Service for the following tax matters:

3 Tax matters

Type of Tax (Income, Employment, Excise, etc.) or Civil Penalty (see the instructions for line 3)	Tax Form Number (1040, 941, 720, etc.)	Year(s) or Period(s) (see the instructions for line 3)
Tax matters in connection with the application for	Form 1120	2006 to 2010
Advanced Coal Project Tax Credits under Section 48A		

4 Specific use not recorded on Centralized Authorization File (CAF). If the power of attorney is for a specific use not recorded on CAF, check this box. See the instructions for **Line 4. Specific uses not recorded on CAF.** . . . . ▶ X

5 Acts authorized. The representatives are authorized to receive and inspect confidential tax information and to perform any and all acts that I (we) can perform with respect to the tax matters described on line 3, for example, the authority to sign any agreements, consents, or other documents. The authority does not include the power to receive refund checks (see line 6 below), the power to substitute another representative, the power to sign certain returns, or the power to execute a request for disclosure of tax returns or return information to a third party. See the line 5 instructions for more information.

Exceptions. An unenrolled return preparer cannot sign any document for a taxpayer and may only represent taxpayers in limited situations. See **Unenrolled Return Preparer** on page 2 of the instructions. An enrolled actuary may only represent taxpayers to the extent provided in section 10.3(d) of Circular 230. See the line 5 instructions for restrictions on tax matters partners.

List any specific additions or deletions to the acts otherwise authorized in this power of attorney: ....

6 Receipt of refund checks. If you want to authorize a representative named on line 2 to receive, **BUT NOT TO ENDORSE OR CASH**, refund checks, initial here ____________ and list the name of that representative below.

Name of representative to receive refund check(s) ▶

7 **Notices and communications.** Original notices and other written communications will be sent to you and a copy to the first representative listed on line 2.
a If you also want the second representative listed to receive a copy of notices and communications, check this box . ▶ ☐
b If you do not want any notices or communications sent to your representative(s), check this box . ▶ ☐

8 **Retention/revocation of prior power(s) of attorney.** The filing of this power of attorney automatically revokes all earlier power(s) of attorney on file with the Internal Revenue Service for the same tax matters and years or periods covered by this document. If you **do not** want to revoke a prior power of attorney, check here ▶ ☐
YOU MUST ATTACH A COPY OF ANY POWER OF ATTORNEY YOU WANT TO REMAIN IN EFFECT.

9 **Signature of taxpayer(s).** If a tax matter concerns a joint return, **both** husband and wife must sign if joint representation is requested, otherwise, see the instructions. If signed by a corporate officer, partner, guardian, tax matters partner, executor, receiver, administrator, or trustee on behalf of the taxpayer, I certify that I have the authority to execute this form on behalf of the taxpayer.
▶ **IF NOT SIGNED AND DATED, THIS POWER OF ATTORNEY WILL BE RETURNED.**

Signature	Date	Title (if applicable)
[signature]	9/5/2006	Chief Financial Officer

Print Name	PIN Number	Print name of taxpayer from line 1 if other than individual
S. Bradford Rives		Louisville Gas and Electric Company

Signature	Date	Title (if applicable)

Print Name	PIN Number

Part II **Declaration of Representative**

Caution: *Students with a special order to represent taxpayers in Qualified Low Income Taxpayer Clinics or the Student Tax Clinic Program, see the instructions for Part II.*

Under penalties of perjury, I declare that:

- I am not currently under suspension or disbarment from practice before the Internal Revenue Service;
- I am aware of regulations contained in Treasury Department Circular No. 230 (31 CFR, Part 10), as amended, concerning the practice of attorneys, certified public accountants, enrolled agents, enrolled actuaries, and others;
- I am authorized to represent the taxpayer(s) identified in Part I for the tax matter(s) specified there; and
- I am one of the following:
  - a Attorney—a member in good standing of the bar of the highest court of the jurisdiction shown below.
  - b Certified Public Accountant—duly qualified to practice as a certified public accountant in the jurisdiction shown below.
  - c Enrolled Agent—enrolled as an agent under the requirements of Treasury Department Circular No. 230.
  - d Officer—a bona fide officer of the taxpayer's organization.
  - e Full-Time Employee—a full-time employee of the taxpayer.
  - f Family Member—a member of the taxpayer's immediate family (i.e., spouse, parent, child, brother, or sister).
  - g Enrolled Actuary—enrolled as an actuary by the Joint Board for the Enrollment of Actuaries under 29 U.S.C. 1242 (the authority to practice before the Service is limited by section 10.3(d) of Treasury Department Circular No. 230).
  - h Unenrolled Return Preparer—the authority to practice before the Internal Revenue Service is limited by Treasury Department Circular No. 230, section 10.7(c)(1)(viii). You must have prepared the return in question and the return must be under examination by the IRS. See **Unenrolled Return Preparer** on page 2 of the instructions.

▶ **IF THIS DECLARATION OF REPRESENTATIVE IS NOT SIGNED AND DATED, THE POWER OF ATTORNEY WILL BE RETURNED.** See the Part II instructions.

Designation—Insert above letter (a-h)	Jurisdiction (state) or identification	Signature	Date
b,e	KY	[signature]	9/5/2006
a,b,e	KY		9/5/2006
b,e	KY	[signature]	9/5/2006

DEPARTMENT OF THE TREASURY
INTERNAL REVENUE SERVICE
WASHINGTON, D.C. 20224

OFFICE OF
CHIEF COUNSEL

August 24, 2006

CC:PSI:6:KReed
PRESP-139681-06

John N. Voyles,
Vice President--Regulated Generation
Kentucky Utilities Company and
Louisville Gas and Electric Company
220 West Main Street
P.O. Box 32030
Louisville, KY 40232

RE: Kentucky Utilities Company; Louisville Gas and Electric Company ("Taxpayers")
Section 48A Application

Dear Mr. Voyles:

This letter acknowledges receipt of Taxpayers' application for section 48A certification that was submitted to the Internal Revenue Service pursuant to section 5.03 of Notice 2006-24, 2006-11 I.R.B. 595.

While the application listed several contact persons, we could not find any Form 2848, Power of Attorney and Declaration of Representative, in the documents attached to the application. Because the application is submitted by two taxpayers, each taxpayer should have submitted a separate completed and signed Form 2848. Accordingly, please advise us as to where in the documents are the two Forms 2848 or please submit the completed and signed two Forms 2848. This information or the Forms 2848 should be faxed to the attention of Douglas Kim at 703-605-1905 or sent to the following address:

Internal Revenue Service
Attn: Douglas Kim, CC:PSI:6
P.O. Box 7604
Ben Franklin Station
Washington, DC 20044

Sincerely,

Kathleen Reed
Senior Technician Reviewer, Branch 6
Office of Associate Chief Counsel
(Passthroughs & Special Industries)
IRS I.D. No. 50-05958

Internal Revenue Service

Department of the Treasury
Washington, DC 20224

Ronald L. Miller
Director Corporate Tax
E.ON U.S.
220 West Main Street
P.O. Box 32030
Louisville, KY 40232

Person To Contact:
Kathleen Reed, ID No. 50-05958
Telephone Number:
(202) 622-3110
Refer Reply To:
CC:PSI:6 – PRESP-139681-06
Date:
October 27, 2006

In re: Section 48A Application
Taxpayers: Louisville Gas and Electric Company (TIN: 61-0264150) and Kentucky Utilities Company (TIN: 61-0247570)
Project: Trimble County Unit 2
Category (Pool): Advanced Coal-Based Generation Technology Other Than IGCC

Dear Mr. Miller:

The enclosed copy of a letter is sent to you under the provisions of a power of attorney and declaration of representative, or other proper authorization, currently on file with the Internal Revenue Service.

Sincerely yours,

Kathleen Reed

KATHLEEN REED
Senior Technician Reviewer, Branch 6
Office of Associate Chief Counsel
(Passthroughs and Special Industries)

Enclosure:
Copy of letter

OFFICE OF CHIEF COUNSEL

DEPARTMENT OF THE TREASURY
INTERNAL REVENUE SERVICE
WASHINGTON, D.C. 20224

October 27, 2006

CC:PSI:6:KReed
PRESP-139681-06

UIL: 48A.00-00

S. Bradford Rives
Chief Financial Officer
E.ON U.S.
220 West Main Street
P.O. Box 32030
Louisville, KY 40232

RE: Section 48A Application
Taxpayers: Louisville Gas and Electric Company (TIN: 61-0264150) and Kentucky Utilities Company (TIN: 61-0247570)
Project: Trimble County Unit 2
Category (Pool): Advanced Coal-Based Generation Technology Other Than IGCC

Dear Mr. Rives:

This letter requests additional information regarding Taxpayers' application for section 48A certification for the Project.

Notice 2006-24, 2006-11 I.R.B. 595, establishes the qualifying advanced coal project program under section 48A of the Internal Revenue Code. Pursuant to section 4.01 of Notice 2006-24, the Internal Revenue Service will consider a project under the qualifying advanced coal project program only if the U.S. Department of Energy provides a certification of feasibility and consistency with energy policy goals ("DOE certification") for the project.

The Project did receive a DOE certification. The following additional information is needed to help us determine whether or not to award credits to the Project.

1. Please provide the number and types of generators to be used for the Project (for example, two combustion turbine generators and one steam turbine generator).

2. The total nameplate generating capacity for a project is the aggregate of the numbers stamped on the nameplate of each generator to be used for the project. Accordingly, please provide the number (in megawatts) stamped on the nameplate of each generator listed in "1" and the aggregate of those numbers. These numbers should be based on the design of the Project as stated in Taxpayers' DOE application

for section 48A certification for the Project. If the aggregate differs from the nameplate generating capacity stated in that application, please also explain the difference.

3. For each generator, please state whether or not the amount stamped on the nameplate is the maximum capacity assuming optimal operating conditions (for example, relative humidity, elevation). If it is, please also list the specific optimal operating conditions that have been assumed (for example, relative humidity of x percent, elevation above sea level of x feet). If it is not the maximum capacity assuming optimal operating conditions, please state what the amount represents and list the assumptions underlying the amount.

4. Please confirm that both Louisville Gas and Electric Company and Kentucky Utilities Company are members of an affiliated group that files a consolidated Federal income tax return. If they are, please provide the name and TIN for the parent corporation of the group that files such return.

The additional information that is requested in this letter must be submitted within 7 calendar days from the date of this letter and must be accompanied by the following declaration: "Under penalties of perjury, I declare that I have examined this information, including accompanying documents, and, to the best of my knowledge and belief, the information contains all the relevant facts relating to the request for the information, and such facts are true, correct, and complete." This penalties of perjury statement must be signed by an officer of the parent corporation of Taxpayers who has personal knowledge of the facts.

Please send a facsimile (fax) transmission of the additional information to my attention at (703) 605-1905 and send the original of the additional information to the following address:

Internal Revenue Service
ADDITIONAL INFORMATION
Attn: Kathleen Reed, CC:PSI:6
P.O. Box 7604
Ben Franklin Station
Washington, DC 20044

Alternatively, if you want to email the additional information to me, please email such information as a pdf file to my email address Kathleen.Reed@IRSCOUNSEL.TREAS.GOV.

In accordance with the power of attorney on file, I am sending (by fax) a copy of this letter to Taxpayers' authorized representative. If you have any questions about this request for additional information, do not hesitate to call me at (202) 622-3110.

Sincerely,

Kathleen Reed

Kathleen Reed
Senior Technician Reviewer, Branch 6
Office of Associate Chief Counsel
(Passthroughs & Special Industries)
IRS I.D. No. 50-05958

cc: Ronald L. Miller
Director Corporate Tax
E.ON U.S.
220 West Main Street
P.O. Box 32030
Louisville, KY 40232

DEPARTMENT OF THE TREASURY
INTERNAL REVENUE SERVICE
WASHINGTON, D.C. 20224

OFFICE OF
CHIEF COUNSEL

November 29, 2006

CC:PSI:6:DHKim
PRESP-139681-06

S. Bradford Rives
Chief Financial Officer
E.ON U.S. LLC
220 West Main Street
P.O. Box 32030
Louisville, KY 40232

RE: Section 48A Application
Taxpayers: Louisville Gas and Electric Company (TIN: 61-0264150) and
Kentucky Utilities Company (TIN: 61-0247570)
Project: Trimble County Unit 2

Dear Mr. Rives:

This letter advises you of our decision regarding Taxpayers' application for section 48A certification for the Project.

We have accepted the Project's application and have allocated $125 million of section 48A credit to the Project. In accordance with section 4.02(11) of Notice 2006-24, 2006-11 I.R.B. 595, enclosed is a closing agreement, in triplicate. As an agent for Taxpayers, a duly authorized officer of E.ON. US Investments Corp. must date and sign the original, duplicate, and triplicate of the closing agreement. By January 31, 2007, Taxpayers must return the original, duplicate, and triplicate of the executed closing agreement to the following address:

Internal Revenue Service
Attn: Douglas Kim, CC:PSI:6, Room 5300
P.O. Box 7604
Ben Franklin Station
Washington, DC 20044

Please submit any suggested changes to the closing agreement on or before December 31, 2006. We will not consider suggested changes submitted after that date. You may fax such changes to my attention at (202) 622-4524. Because we are moving between December 8-11, please do not submit your changes by fax until after December 12, 2006. Alternatively, you may submit your changes to me as a pdf file to my email address Kathleen.Reed@IRSCOUNSEL.TREAS.GOV.

In accordance with the power of attorney on file, I am sending a copy of this letter to Taxpayer's authorized representative. If you have any questions, do not hesitate to call me or Douglas Kim at (202) 622-3110.

Sincerely,

Kathleen Reed

Kathleen Reed
Senior Technician Reviewer, Branch 6
Office of Associate Chief Counsel
(Passthroughs & Special Industries)
IRS I.D. No. 50-05958

cc: Ronald L. Miller
Director Corporate Tax
E.ON U.S. LLC
220 West Main Street
P.O. Box 32030
Louisville, KY 40232

DEPARTMENT OF TREASURY – INTERNAL REVENUE SERVICE

CLOSING AGREEMENT

Under § 7121 of the Internal Revenue Code, E.ON US Investments Corp., 220 West Main Street, P.O. Box 32030, Louisville, KY 40232 (TIN: 61-1378946), on behalf of itself and as agent for Kentucky Utilities Company, 220 West Main Street, P.O. Box 32030, Louisville, KY 40232 (TIN: 61-0247570) and Louisville Gas and Electric Company, 220 West Main Street, P.O. Box 32030, Louisville, KY 40232 (TIN: 61-0264150), members of E.ON US Investments Corp.'s affiliated group, and the Commissioner of Internal Revenue ("Commissioner") make the following closing agreement:

WHEREAS:

1. On or before October 2, 2006, Kentucky Utilities Company and Louisville Gas and Electric Company (collectively, "KULGEC") submitted to the Internal Revenue Service ("IRS"), an application for certification under the qualifying advanced coal project program described in Notice 2006-24 ("Application for § 48A Certification");

2. KULGEC's Application for § 48A Certification is for the qualifying advanced coal project (the "Project") described below--

(1) The Project will use an advanced coal-based technology (as defined in § 48A(c)(2) and (f)) other than an integrated gasification combined cycle;

(2) The Project will be located at 487 Corn Creek Road, Bedford, Kentucky 40006;

(3) The Project is a new electric generation unit (as defined in

§ 48A(c)(6));

(4) The Project will have a total nameplate generating capacity (that is, the aggregate of the numbers stamped on the nameplate of each generator to be used for the Project) of 833.6 megawatts;

and

3. On November 29, 2006, the IRS accepted KULGEC's Application for § 48A Certification for the Project and allocated a qualifying advanced coal project credit under § 48A in the amount of $125 million to the Project.

NOW IT IS HEREBY DETERMINED AND AGREED FOR FEDERAL INCOME TAX PURPOSES THAT:

1. The total amount of the qualifying advanced coal project credit to be claimed for the Project under § 48A(a) must not exceed $125 million.

2. If KULGEC fails to satisfy any of the certification requirements in § 48A(e)(2) within 2 years of November 29, 2006, or if the IRS does not issue a certification for the Project under Notice 2006-24, the qualifying advanced coal project credit in the amount of $125 million allocated to the Project is fully forfeited.

3. If the Project is not placed in service by KULGEC within 5 years of the date of issuance of the certification as determined under section 6.03 of Notice 2006-24, the qualifying advanced coal project credit in the amount of $125 million allocated to the Project is fully forfeited.

4. If the Project does not have a total nameplate generating capacity of 833.6 megawatts on the date the Project is placed in service, the qualifying advanced coal project credit in the amount of $125 million allocated to the Project is reduced

proportionately.

5. If the Project fails to satisfy any of the requirements in § 48A(e)(1)(A), (C), (D), (E), and (F) for a qualifying advanced coal project or in normal plant operations (operations other than initial plant certification and plant startup and shutdown periods) fails to satisfy the requirement in § 48A(e)(1)(B) for a qualifying advanced coal project--

(1) at the time the Project is placed in service, the qualifying advanced coal project credit in the amount of $125 million allocated to the Project is fully forfeited; and

(2) after the Project is placed in service (and after satisfying all such requirements at the time the Project is placed in service), the Project ceases to be investment credit property and the recapture rules of § 50(a) apply.

6. E.ON US Investments Corp. and KULGEC (collectively, the "Taxpayers") will not claim the qualifying gasification project credit under § 48B for any qualified investment for which the qualifying advanced coal project credit is allowed under § 48A.

7. If Taxpayers elect to claim the qualifying advanced coal project credit on the qualified progress expenditures paid or incurred by KULGEC during the taxable year for construction of a qualifying advanced coal project, rules similar to the recapture rules in § 50(a)(2)(A) through (D) apply.

8. This agreement applies only to Taxpayers. Any successor in interest must execute a new closing agreement with the IRS. If the interest is acquired at or before the time the Project is placed in service and the successor in interest fails to execute a new closing agreement, the qualifying advanced coal project credit in the amount of $125 million allocated to the Project is fully forfeited. If the interest is acquired after the

time the Project is placed in service and the successor in interest fails to execute a new closing agreement, the Project ceases to be investment credit property and the recapture rules of § 50(a) apply.

THIS AGREEMENT IS FINAL AND CONCLUSIVE EXCEPT:

1. The matter it relates to may be reopened in the event of fraud, malfeasance, or misrepresentation of a material fact;

2. It is subject to the Internal Revenue Code sections that expressly provide that effect be given to their provisions (including any stated exception for § 7122) notwithstanding any law or rule of law; and

3. If it relates to a tax period ending after the date of this Closing Agreement, it is

subject to any law enacted after such date, which applies to the tax period.

By signing, the parties certify that they have read and agreed to the terms of this Closing Agreement.

Taxpayer: E.ON US Investments Corp. (TIN: 61-1378946)

By: ______________________________ **Date Signed:** __________

Print Name: ___________________________

Title: ___________________________
E.ON US Investments Corp.

Commissioner of Internal Revenue

By: ______________________________ **Date Signed:** __________
William P. O'Shea

Title: Associate Chief Counsel, Passthroughs and Special Industries, CC:PSI

Internal Revenue Service

Department of the Treasury
Washington, DC 20224

Third Party Communication: None
Date of Communication: Not Applicable

S. Bradford Rives
Chief Financial Officer
E.ON U.S. LLC
220 West Main Street
P.O. Box 32030
Louisville, KY 40232

Person To Contact:
Douglas Kim, ID No. 50-12306
Telephone Number:
(202) 622-3110
Refer Reply To:
CC:PSI:6
PRESP-139681-06
Date:
March 30, 2007

Date Closing Agreement Approved: March 22, 2007

Dear Mr. Rives:

The Associate Chief Counsel (Passthroughs and Special Industries) of the Office of Chief Counsel, Internal Revenue Service, approved your closing agreement on the date shown above.

I have enclosed the signed duplicate of the agreement for your records.

Thank you for your cooperation.

Sincerely,

Kathleen Reed

KATHLEEN REED
Senior Technician Reviewer, Branch 6
Office of Associate Chief Counsel
(Passthroughs & Special Industries)

Enclosure (1)
Duplicate of closing agreement

cc (w/o Enclosure):

Ronald L. Miller
Director Corporate Tax
E.ON U.S. LLC
220 West Main Street
P.O. Box 32030
Louisville, KY 40232

Duplicate

DEPARTMENT OF TREASURY – INTERNAL REVENUE SERVICE

CLOSING AGREEMENT

Under § 7121 of the Internal Revenue Code, E.ON US Investments Corp., 220 West Main Street, P.O. Box 32030, Louisville, KY 40232 (TIN: 61-1378946), on behalf of itself and as agent for Kentucky Utilities Company, 220 West Main Street, P.O. Box 32030, Louisville, KY 40232 (TIN: 61-0247570) and Louisville Gas and Electric Company, 220 West Main Street, P.O. Box 32030, Louisville, KY 40232 (TIN: 61-0264150), members of E.ON US Investments Corp.'s affiliated group, and the Commissioner of Internal Revenue ("Commissioner") make the following closing agreement:

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1. On or before October 2, 2006, Kentucky Utilities Company and Louisville Gas and Electric Company (collectively, "KULGEC") submitted to the Internal Revenue Service ("IRS"), an application for certification under the qualifying advanced coal project program described in Notice 2006-24 ("Application for § 48A Certification");

2. KULGEC's Application for § 48A Certification is for the qualifying advanced coal project (the "Project") described below--

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(2) The Project will be located at 487 Corn Creek Road, Bedford, Kentucky 40006;

(3) The Project is a new electric generation unit (as defined in

§ 48A(c)(6)); and

(4) The Project will have a total nameplate generating capacity (that is, the aggregate of the numbers stamped on the nameplate of each steam turbine generator to be used in the Project) of at least 833.6 megawatts;

and

3. On November 29, 2006, the IRS accepted KULGEC's Application for § 48A Certification for the Project and allocated a qualifying advanced coal project credit under § 48A in the amount of $125 million to the Project.

NOW IT IS HEREBY DETERMINED AND AGREED FOR FEDERAL INCOME TAX PURPOSES THAT:

1. The total amount of the qualifying advanced coal project credit to be claimed for the Project under § 48A(a) must not exceed $125 million.

2. If KULGEC fails to satisfy any of the certification requirements in § 48A(e)(2) within the time specified in § 48A(d)(2)(D) from November 29, 2006, or if the IRS does not issue a certification for the Project under Notice 2006-24, the qualifying advanced coal project credit in the amount of $125 million allocated to the Project is fully forfeited.

3. If the Project is not placed in service by KULGEC within 5 years of the date of issuance of the certification as determined under section 6.03 of Notice 2006-24, the qualifying advanced coal project credit in the amount of $125 million allocated to the Project is fully forfeited.

4. If, on the date the Project is placed in service, the Project does not have a total nameplate generating capacity (that is, the aggregate of the numbers stamped on the nameplate of each steam turbine generator used in the Project) of at least 833.6

megawatts, the qualifying advanced coal project credit in the amount of $125 million allocated to the Project is reduced proportionately.

5. If the Project fails to satisfy any of the requirements in § 48A(e)(1)(A), (C), (D), (E), and (F) for a qualifying advanced coal project or in normal plant operations (operations other than initial plant certification, plant startup periods, plant shutdown periods, periods of gasification system maintenance during which the integrated gasifier is shutdown, or interruptions of coal supply to the Project resulting from an event of force majeure (including an Act of God, war, strike, or other similar event beyond the control of KULGEC)) fails to satisfy the requirement in § 48A(e)(1)(B) for a qualifying advanced coal project--

(1) at the time the Project is placed in service, the qualifying advanced coal project credit in the amount of $125 million allocated to the Project is fully forfeited; and

(2) after the Project is placed in service (and after satisfying all such requirements at the time the Project is placed in service), the Project ceases to be investment credit property and the recapture rules of § 50(a) apply.

6. E.ON US Investments Corp. and KULGEC (collectively, the "Taxpayers") will not claim the qualifying gasification project credit under § 48B for any qualified investment for which the qualifying advanced coal project credit is allowed under § 48A.

7. If Taxpayers elect to claim the qualifying advanced coal project credit on the qualified progress expenditures paid or incurred by KULGEC during the taxable year(s) during which the Project is under construction and if the Project ceases to be a qualifying advanced coal project (before, at the time, or after the Project is placed in

service), rules similar to the recapture rules in § 50(a)(2)(A) through (D) apply.

8. This agreement applies only to Taxpayers. Any successor in interest must execute a new closing agreement with the IRS. If the interest is acquired at or before the time the Project is placed in service and the successor in interest fails to execute a new closing agreement, the qualifying advanced coal project credit in the amount of $125 million allocated to the Project is fully forfeited. If the interest is acquired after the time the Project is placed in service and the successor in interest fails to execute a new closing agreement, the Project ceases to be investment credit property and the recapture rules of § 50(a) apply.

THIS AGREEMENT IS FINAL AND CONCLUSIVE EXCEPT:

1. The matter it relates to may be reopened in the event of fraud, malfeasance, or misrepresentation of a material fact;

2. It is subject to the Internal Revenue Code sections that expressly provide that effect be given to their provisions (including any stated exception for § 7122) notwithstanding any law or rule of law; and

3. If it relates to a tax period ending after the date of this Closing Agreement, it is

subject to any law enacted after such date, which applies to the tax period.

By signing, the parties certify that they have read and agreed to the terms of this Closing Agreement.

Taxpayer: E.ON US Investments Corp. (TIN: 61-1378946)

By: SBRives **Date Signed:** 1/29/07

Print Name: S. BRADFORD RIVES

Title: CFO
E.ON US Investments Corp.

Commissioner of Internal Revenue

By: William P. O'Shea **Date Signed:** 3-22-07
William P. O'Shea

Title: Associate Chief Counsel, Passthroughs and Special Industries, CC:PSI

I have examined the specific matters involved and recommend the acceptance of the proposed agreement.

(Receiving Officer) Douglas Kim

(Title) Attorney-Advisor

Date Signed 3/9/07

~~I have reviewed the specific matters involved and recommend~~ the acceptance of the proposed agreement.

(Reviewing Officer) Kathleen R

(Title) Senior Technician Reviewer, CC:PSI:6

Date Signed 3/12/07

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

APPLICATION OF KENTUCKY UTILITIES COMPANY FOR AN ORDER AUTHORIZING INCLUSION OF INVESTMENT TAX CREDITS IN CALCULATION OF ENVIRONMENTAL SURCHARGE AND DECLARING APPROPRIATE RATEMAKING METHODS FOR BASE RATES	)	CASE NO. 2007-00178

DIRECT TESTIMONY OF
KENT W. BLAKE
VICE PRESIDENT, STATE REGULATION AND RATES
E.ON U.S. SERVICES INC.

Filed: May 4, 2007

Q. Please state your name, position and business address.

A. My name is Kent W. Blake. I am the Vice President, State Regulation and Rates for E.ON U.S. Services Inc., which provides services to Louisville Gas and Electric Company ("LG&E") and Kentucky Utilities Company ("KU") (collectively, "the Companies"). My business address is 220 West Main Street, Louisville, Kentucky 40202. A complete statement of my education and work experience is attached to this testimony as Appendix A.

Q. Have you previously testified before this Commission?

A. Yes. I have testified several times, including Case Nos. 2004-00426[1] and 2006-00206[2], KU's most recent Environmental Cost Recovery applications.

Q. Are you sponsoring any exhibits?

A. Yes, I am sponsoring the following five exhibits:

(1) Exhibit KWB-1 is an illustration of the "ratable restoration" methodology;

(2) Exhibit KWB-2 contains the estimated construction expenditures for Trimble County Unit 2 ("TC2");

(3) Exhibit KWB-3 contains copies of applicable pages from Commission's Order in Case No. 2003-00434;

(4) Exhibit KWB-4 shows the current and proposed revisions to ES Forms 2.00 and 2.10; and

(5) Exhibit KWB-5 is the proposed rate base treatment of the ECR rate base in the next base rate case.

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[1] *In the Matter of: The Application of Kentucky Utilities Company for a Certificate of Public Convenience and Necessity to Construct Flue Gas Desulfurization Systems and Approval of its 2004 Compliance Plan for Recovery by Environmental Surcharge.*

[2] *In the Matter of: The Application of Kentucky Utilities Company for a Certificate of Public Convenience and Necessity to Construct a Selective Catalytic Reduction System and Approval of its 2006 Compliance Plan for Recovery by Environmental Surcharge.*

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to describe how KU will provide its customers the benefit, consistent with tax law, of its portion of the $125 million advanced coal project investment tax credit ("'05 EPA ITC") that it and LG&E have been allocated under the provisions of the Energy Policy Act of 2005 (see 26 U.S.C. § 48A) for their investment in Trimble County Unit 2 ("TC2"). (The testimony of KU witness Ronald L. Miller discusses the credit itself and how the Companies obtained it.) I will also discuss a related ratemaking matter that arises from the recognition of the '05 EPA ITC in both the environmental surcharge and base rates to ensure no double counting of the credit. Finally I will present revised ES Forms 2.00 and 2.10 for approval.

Q. What is KU's portion of the $125 million in '05 EPA ITC?

A. Because Illinois Municipal Electric Agency and Indiana Municipal Power Agency will not receive any portion of the '05 EPA ITC, KU and LG&E will be allocated the credit in proportion to their respective ownership interests in TC2. Thus, assuming the facility qualifies for the maximum credit allocated, KU's portion of the '05 EPA ITC will be 81 percent of $125,000,000, which is $101,250,000.

Q. What ratemaking methodology will KU use with regard to its portion of the '05 EPA ITC?

A. KU will use its long-standing method of adjusting rate base by its pro rata share of the unamortized balance of the '05 EPA ITC. In so doing, KU's revenue requirement associated with its investment in TC2 will be lower than it otherwise would be due to the award of the '05 EPA ITC. Thus, KU's customers will benefit by paying lower rates. This is sometimes referred to as the "ratable restoration" method since it reduces the utilities rate base by the amount of the credit and then restores the rate base as the credit is amortized over the life of the asset. An illustration of this methodology is attached hereto as Exhibit KWB-1.

Q. Are there any additional tax implications associated with the '05 EPA ITC that will impact rates?

A. Yes. The Energy Policy Act of 2005 provided that the '05 EPA ITC would serve to reduce the tax basis in the underlying asset for the recipient. This serves to lower KU's tax deductions for depreciation over the life of the asset and thus increase its income tax expense and its cost of service (see columns 9 and 10 in Exhibit KWB-1).

Q. How will KU implement the "ratable restoration" method?

A. As qualifying expenditures are incurred, KU increases its construction work-in-progress ("CWIP") balance. Likewise, as KU earns the '05 EPA ITC for those qualifying expenditures, it will increase its deferred investment tax credit balance. The CWIP balance and deferred investment tax credit balance would both impact KU's capitalization and would thus be considered in calculating KU's net operating income found reasonable in future base rate cases.

Q. Has KU used this method in the past to share with customers the benefits from other forms of investment tax credit?

A. Yes. In 1972, KU made an irrevocable election under then-extant 26 U.S.C. §46(f)(1) that continues, through the current 26 U.S.C. §50(d)(2), to require that KU reduce its rate base by its share of the credit. Since then, KU's customers have shared in the benefit of the earlier investment tax credits available under the Revenue Act of 1971

(P.L. 92-178) by paying rates that were effectively reduced by the adjustment to KU's rate base.

Additionally, prior to the implementation of the Final Order in Case No. 93-435 (KU's original ECR plan), KU excluded from ECR rate base the unamortized portion of prior investment tax credits that were associated with projects included in the original ECR approved project list. (Following implementation of the Final Order, the investment tax credit adjustment to ECR rate base was eliminated because the credits were associated with assets that were removed from ECR recovery due to their original in-service dates.)

Q. Has the Commission historically approved this method of rate treatment for investment tax credits for KU?

A. Yes. The Commission has historically and consistently approved this method for KU rate treatment of investment tax credits. As early as 1981, in Case No. 8177 (a KU rate case), the Commission recognized that the appropriate treatment for an investment tax credit for KU was to reduce rate base by the amount of the credit.[3] Just a year and a half later in a separate KU rate case (Case No. 8624), the Commission approvingly recalled Case No. 8177, stating, "The 3 percent investment tax credits were included as a reduction to the rate base in Case 8177," and again included the investment tax credits at issue as a reduction to rate base.[4] In KU's latest rate case, Case No. 2003-00434, the Commission again recognized that investment

[3] *In the Matter of General Adjustment of Electric Rates of Kentucky Utilities Company*, Case No. 8177, Order at 10-11 (September 11, 1981).
[4] *In the Matter of General Adjustment of Electric Rates of Kentucky Utilities Company*, Case No. 8624, Order at 3 (March 18, 1983).

tax credits were appropriately removed from rate base.[5] A copy of the applicable pages is attached hereto as Exhibit KWB-3. This rate treatment of KU's investment tax credits is, therefore, both required by federal law and long-recognized by the Commission.

Q. How does KU's elected treatment of investment tax credits compare with the one LG&E has elected?

A. Where KU made its election under 26 U.S.C. § 46(f)(1), LG&E made its election under former 26 U.S.C. § 46(f)(2). This method is sometimes referred to as the "ratable flow through method" as a utility's cost of service in a given year is reduced by the amount of the investment tax credits it amortizes in that year. In lieu of receiving the benefit of the credit directly via the amortization of said credit, KU customers receive the benefit of a lower cost of capital by having rate base reduced by the unamortized investment tax credit balance.

Q. Could KU use the rate treatment available to LG&E concerning the '05 EPA ITC?

A. No. Just as LG&E could not use KU's rate treatment, KU could not use LG&E's rate treatment as both elections are irrevocable. As discussed in Mr. Miller's testimony, KU cannot change its 26 U.S.C. § 46(f)(1) election, nor can it otherwise depart from its elected rate making treatment, without losing the credit itself.

Q. Should a portion of KU's share of the '05 EPA ITC be included in the calculation of KU's environmental surcharge?

[5] *In the Matter of an Adjustment of the Electric Rates, Terms, and Conditions of Kentucky Utilities Company*, Case No. 2003-00434, Order at 15 (June 30, 2004).

A. Yes. On December 22, 2006, the Commission issued its Order in Case No. 2006-00206, approving KU's application for recovery through its ES tariff, among other projects the ECR-eligible portion of KU's investment in TC2 (Project No. 23). To the extent Project No. 23 is being recovered through the ECR, KU's environmental rate base will be reduced by the unamortized balance of the investment tax credits it receives. To the extent Project No. 23 is being recovered through base rates, the same benefit will instead be provided through base rates. Regardless of the rate mechanism utilized, customers of KU will receive the benefits of the '05 EPA ITC through the reduction in rate base.

Q. What portion of KU's '05 EPA ITC balance will be associated with Project No. 23 and thus potentially credited to customers through the ECR mechanism?

A. The Commission approved the recovery of this project (Project No. 23) as part of KU's Environmental Surcharge Compliance Plan in its December 22, 2006 Order in Case No. 2006-00206. The environmental pollution control equipment represents approximately 23% of the "qualified investment" in TC2 as discussed by Mr. Miller. Therefore, the inclusion of this pro rata allocation of the credit should result in approximately twenty-three percent of the '05 EPA ITC being allocated to KU's environmental surcharge rate base. Attached hereto as Exhibit KWB-2 is a chart showing the actual expenditures for 2006 and the remaining estimated construction expenditures (including all "qualified investment") for TC2 through the expected in-service date of 2010, including the pollution control equipment that is approved for recovery through KU's environmental surcharge and the pro rata amount of the '05 EPA ITC associated with that investment. The illustrative example in Exhibit KWB-

1 also distinguishes between the portions of the '05 EPA ITC associated with environmental expenditures and those associated with the balance of plant as the benefits of each could be provided through different rate mechanisms and because the depreciable lives of the underlying assets are different. The reductions in rate base for the '05 EPA ITC must be ratably restored over the regulatory life of the air quality control system portion of TC2, which presently is set at 28.8 years, and could be provided to customers through a combination of the ECR mechanism and base rates. The reductions in rate base for the balance of the '05 EPA ITC must be ratably restored over the regulatory life of the balance of the plant, which is presently set at 41.5 years, and will be provided to customers through base rates.

Q. Are there any modifications to the ECR forms to accommodate accounting for the '05 EPA ITC in the monthly filings?

A. Yes. Attached as Exhibit KWB-4 is the current version and proposed revisions to ES Forms 2.00 and 2.10 to account for the '05 EPA ITC KU proposes to include in the environmental surcharge calculations. In Case No. 2006-00206 KU simplified the forms to remove items not being utilized and to achieve consistency between the LG&E and KU filings. At that time the rows and columns on ES Forms 2.00 and 2.10 relating to ITC were not being utilized and were subsequently removed. However, with LG&E and KU being awarded the '05 EPA ITC for TC2, those rows and columns will be needed to account for the '05 EPA ITC related to TC2. As such, KU is proposing to add back the related rows and columns on ES Forms 2.00 and 2.10.

Q. Will the benefit of the '05 EPA ITC be fully accounted for in KU's general and environmental surcharge rate bases?

A. Yes. KU's '05 EPA ITC will be fully accounted for between KU's general and environmental surcharge rate bases and thus between KU's electric base rates and KU's ECR charges. As I discussed above, a pro rata share of the overall reduction in rate base due to the credit will be allocated to KU's environmental surcharge rate base. Careful allocation of the credit between the rate bases ensures that there will be no double-counting of any kind, and thus no over- or under-recovery.

Q. How does KU propose to ensure that no double counting of the credit arises from the recognition of the '05 EPA ITC in both the environmental surcharge and base rates?

A. KU proposes to exclude the ECR rate base from Kentucky jurisdictional rate base, and to determine the percentage of Kentucky jurisdictional rate base (excluding ECR) to total company rate base when allocating capitalization in the next electric base rate case. Since the ECR revenue requirement is derived by the rate base methodology, this proposal provides consistency between Kentucky jurisdictional rate base and capitalization, as well as ensuring that the ECR rate base not recovered in base rates is excluded from the determination of base rates. KU has used this same methodology for many years to allocate the appropriate amount of capital to Kentucky and Virginia retail jurisdictions and wholesale jurisdictions. Exhibit KWB-5 attached hereto illustrates this proposal.

In addition, consistent with prior Commission practice KU proposes to exclude ECR revenues and expenses not recovered in base rates in the next electric base rate case.

Q. What is KU requesting from the Commission in this proceeding?

A. KU requests that the Commission issue an order: (1) authorizing the inclusion in the calculation of the environmental surcharge of that portion of KU's advanced coal project investment tax credit that is related to projects approved for recovery through the environmental surcharge; (2) approving the revised ES Forms 2.00 and 2.10; and (3) declaring the proposed rate base and capitalization treatments of the 2005 Energy Policy Act Investment Tax Credit and the proposed allocation of Kentucky jurisdictional rate base to be the appropriate ratemaking methods for the determination of base rates.

Q. Does this conclude your testimony?

A. Yes, it does.

VERIFICATION

COMMONWEALTH OF KENTUCKY)
) SS:
COUNTY OF JEFFERSON)

The undersigned, **Kent W. Blake**, being duly sworn, deposes and says he is Vice President, State Regulation and 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.

Kent W Blake
KENT W. BLAKE

Subscribed and sworn to before me, a Notary Public in and before said County and State, this 4th day of May, 2007.

Tammy J. Elzy (SEAL)
Notary Public

My Commission Expires:
November 9, 2010

APPENDIX A

Kent W. Blake

Vice President, State Regulation and Rates
E.ON U.S. Services Inc.
220 West Main Street
P. O. Box 32010
Louisville, Kentucky 40202
(502) 627-2573

Education

University of Kentucky, B.S. in Accounting, 1988
Certified Public Accountant, Kentucky, 1991
E.ON AG Executive Pool, 2005/2006
Leadership Louisville, 2007
Multiple industry and executive development programs

Previous Positions

LG&E Energy LLC, Louisville, Kentucky
- 2004 (Oct) – 2007 (Apr) – Director, State Regulation and Rates
- 2003 (Sept) – 2004 (Oct) – Director, Regulatory Initiatives
- 2003 (Feb) – 2003 (Sept) – Director, Business Development
- 2002 (Aug) – 2003 (Feb) – Director, Finance and Business Analysis

Mirant Corporation (f.k.a. Southern Company Energy Marketing)
- 2002 (Feb-Aug) – Senior Director, Applications Development
- 2000-2002 – Director, Systems Integration
- 1998-2000 – Trading Controller

LG&E Energy Corp.
- 1997-1998 – Director, Corporate Accounting and Trading Controls

Arthur Andersen LLP
- 1992-1997 – Manager, Audit and Business Advisory Services
- 1990-1992 – Senior Auditor
- 1988-1990 – Audit Staff

Kentucky Utilities Company

Ratemaking Treatment of the Advanced Coal Tax Credit
Ratable Restoration Method

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
	Unamortized Advanced Coal Tax Credit			Impact of Lower Capitalization		Tax Credit Amortization		Impact of Lower Tax Basis on Asset		Tax Credit Benefit to Customers		
	Environmental Portion	Balance of Plant	Total	Environmental Portion	Balance of Plant	Environmental Portion	Balance of Plant	Environmental Portion	Balance of Plant	Environmental Portion	Balance of Plant	Total
Year	Per Exhibit KWB-2	Per Exhibit KWB-2	(2) + (3)	(2) x 11.75%	(3) x 11.75%	(2) for 2009 x 3.47%	(3) for 2009 x 2.41%	(7) / (1 - 35%) x 35%	(8) / (1 - 35%) x 35%	(5) - (9)	(6) - (10)	(11) + (12)
2006	1,430,255	10,569,745	12,000,000	168,055	1,241,945					168,055	1,241,945	1,410,000
2007	9,761,950	42,991,142	52,753,092	1,147,029	5,051,459					1,147,029	5,051,459	6,198,488
2008	22,246,526	72,460,367	94,706,893	2,613,967	8,514,093					2,613,967	8,514,093	11,128,060
2009	23,409,000	77,841,000	101,250,000	2,750,558	9,146,318					2,750,558	9,146,318	11,896,875
2010	23,002,854	76,903,016	99,905,870	2,702,835	9,036,104	406,146	937,984	218,694	505,068	2,484,141	8,531,036	11,015,177
2011	22,190,562	75,027,048	97,217,609	2,607,391	8,815,678	812,292	1,875,968	437,388	1,010,137	2,170,003	7,805,541	9,975,544
2012	21,378,269	73,151,080	94,529,349	2,511,947	8,595,252	812,292	1,875,968	437,388	1,010,137	2,074,558	7,585,115	9,659,674
2013	20,565,977	71,275,112	91,841,089	2,416,502	8,374,826	812,292	1,875,968	437,388	1,010,137	1,979,114	7,364,689	9,343,803
2014	19,753,685	69,399,144	89,152,828	2,321,058	8,154,399	812,292	1,875,968	437,388	1,010,137	1,883,670	7,144,263	9,027,932
2015	18,941,392	67,523,175	86,464,568	2,225,614	7,933,973	812,292	1,875,968	437,388	1,010,137	1,788,225	6,923,836	8,712,062
2016	18,129,100	65,647,207	83,776,307	2,130,169	7,713,547	812,292	1,875,968	437,388	1,010,137	1,692,781	6,703,410	8,396,191
2017	17,316,808	63,771,239	81,088,047	2,034,725	7,493,121	812,292	1,875,968	437,388	1,010,137	1,597,337	6,482,984	8,080,321
2018	16,504,515	61,895,271	78,399,787	1,939,281	7,272,694	812,292	1,875,968	437,388	1,010,137	1,501,892	6,262,558	7,764,450
2019	15,692,223	60,019,303	75,711,526	1,843,836	7,052,268	812,292	1,875,968	437,388	1,010,137	1,406,448	6,042,131	7,448,579
2020	14,879,931	58,143,335	73,023,266	1,748,392	6,831,842	812,292	1,875,968	437,388	1,010,137	1,311,004	5,821,705	7,132,709
2021	14,067,639	56,267,367	70,335,005	1,652,948	6,611,416	812,292	1,875,968	437,388	1,010,137	1,215,559	5,601,279	6,816,838
2022	13,255,346	54,391,399	67,646,745	1,557,503	6,390,989	812,292	1,875,968	437,388	1,010,137	1,120,115	5,380,853	6,500,968
2023	12,443,054	52,515,431	64,958,485	1,462,059	6,170,563	812,292	1,875,968	437,388	1,010,137	1,024,671	5,160,426	6,185,097
2024	11,630,762	50,639,463	62,270,224	1,366,614	5,950,137	812,292	1,875,968	437,388	1,010,137	929,226	4,940,000	5,869,227
2025	10,818,469	48,763,494	59,581,964	1,271,170	5,729,711	812,292	1,875,968	437,388	1,010,137	833,782	4,719,574	5,553,356
2026	10,006,177	46,887,526	56,893,703	1,175,726	5,509,284	812,292	1,875,968	437,388	1,010,137	738,338	4,499,148	5,237,485
2027	9,193,885	45,011,558	54,205,443	1,080,281	5,288,858	812,292	1,875,968	437,388	1,010,137	642,893	4,278,721	4,921,615
2028	8,381,592	43,135,590	51,517,183	984,837	5,068,432	812,292	1,875,968	437,388	1,010,137	547,449	4,058,295	4,605,744
2029	7,569,300	41,259,622	48,828,922	889,393	4,848,006	812,292	1,875,968	437,388	1,010,137	452,005	3,837,869	4,289,874
2030	6,757,008	39,383,654	46,140,662	793,948	4,627,579	812,292	1,875,968	437,388	1,010,137	356,560	3,617,443	3,974,003
2031	5,944,716	37,507,686	43,452,401	698,504	4,407,153	812,292	1,875,968	437,388	1,010,137	261,116	3,397,016	3,658,132
2032	5,132,423	35,631,718	40,764,141	603,060	4,186,727	812,292	1,875,968	437,388	1,010,137	165,672	3,176,590	3,342,262
2033	4,320,131	33,755,750	38,075,881	507,615	3,966,301	812,292	1,875,968	437,388	1,010,137	70,227	2,956,164	3,026,391
2034	3,507,839	31,879,782	35,387,620	412,171	3,745,874	812,292	1,875,968	437,388	1,010,137	(25,217)	2,735,738	2,710,521
2035	2,695,546	30,003,813	32,699,360	316,727	3,525,448	812,292	1,875,968	437,388	1,010,137	(120,661)	2,515,311	2,394,650

Kentucky Utilities Company

Ratemaking Treatment of the Advanced Coal Tax Credit

Ratable Restoration Method

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
	Unamortized Advanced Coal Tax Credit			Impact of Lower Capitalization		Tax Credit Amortization		Impact of Lower Tax Basis on Asset		Tax Credit Benefit to Customers		
	Environmental Portion	Balance of Plant	Total	Environmental Portion	Balance of Plant	Environmental Portion	Balance of Plant	Environmental Portion	Balance of Plant	Environmental Portion	Balance of Plant	Total
Year	Per Exhibit KWB-2	Per Exhibit KWB-2	(2) + (3)	(2) x 11.75%	(3) x 11.75%	(2) for 2009 x 3.47%	(3) for 2009 x 2.41%	(7) / (1 - 35%) x 35%	(8) / (1 - 35%) x 35%	(5) - (9)	(6) - (10)	(11) + (12)
2036	1,883,254	28,127,845	30,011,099	221,282	3,305,022	812,292	1,875,968	437,388	1,010,137	(216,106)	2,294,885	2,078,779
2037	1,070,962	26,251,877	27,322,839	125,838	3,084,596	812,292	1,875,968	437,388	1,010,137	(311,550)	2,074,459	1,762,909
2038	258,669	24,375,909	24,634,579	30,394	2,864,169	812,292	1,875,968	437,388	1,010,137	(406,995)	1,854,033	1,447,038
2039	-	22,499,941	22,499,941	-	2,643,743	258,669	1,875,968	139,284	1,010,137	(139,284)	1,633,606	1,494,323
2040	-	20,623,973	20,623,973	-	2,423,317	-	1,875,968	-	1,010,137	0	1,413,180	1,413,180
2041	-	18,748,005	18,748,005	-	2,202,891	-	1,875,968	-	1,010,137	0	1,192,754	1,192,754
2042	-	16,872,037	16,872,037	-	1,982,464	-	1,875,968	-	1,010,137	0	972,328	972,328
2043	-	14,996,069	14,996,069	-	1,762,038	-	1,875,968	-	1,010,137	0	751,901	751,901
2044	-	13,120,101	13,120,101	-	1,541,612	-	1,875,968	-	1,010,137	0	531,475	531,475
2045	-	11,244,132	11,244,132	-	1,321,186	-	1,875,968	-	1,010,137	0	311,049	311,049
2046	-	9,368,164	9,368,164	-	1,100,759	-	1,875,968	-	1,010,137	0	90,623	90,623
2047	-	7,492,196	7,492,196	-	880,333	-	1,875,968	-	1,010,137	0	(129,804)	(129,804)
2048	-	5,616,228	5,616,228	-	659,907	-	1,875,968	-	1,010,137	0	(350,230)	(350,230)
2049	-	3,740,260	3,740,260	-	439,481	-	1,875,968	-	1,010,137	0	(570,656)	(570,656)
2050	-	1,864,292	1,864,292	-	219,054	-	1,875,968	-	1,010,137	0	(791,082)	(791,082)
2051	-	-	-	-	-	-	1,864,292	-	1,003,850	0	(1,003,850)	(1,003,850)
Totals				46,311,429	213,684,568	23,409,000	77,841,000	12,604,846	41,914,385	33,706,583	171,770,183	205,476,766

In order to simplify the illustration of KU's ratable restoration ratemaking treatment, the following assumptions were made:

- The impact on deferred taxes due to timing differences has been omitted
- Perfect rate treatment is assumed
- For illustration purposes only, the weighted average cost of capital is assumed to be equal to 11.75%
- For illustration purposes only, the consolidated tax rate is assumed to be equal to 35%

Louisville Gas and Electric Company and Kentucky Utilities Company
2005 Energy Policy Act -- Investment Tax Credit "Qualified Investment"
Trimble County Unit 2 Construction Schedule

	2006	2007	2008	2009	2010	Total
Louisville Gas and Electric						
Trimble County Unit 2 Air Quality Control Systems	$ 2,736,000	$ 13,028,989	$ 19,523,205	$ 6,730,361	$ 1,433,835	$ 43,452,390
Investment Tax Credit for Air Quality Control Systems	279,846	1,954,348	2,928,481	147,825	-	5,310,500
Balance of Trimble County 2 Capital Expenditures	26,594,464	50,700,126	46,083,562	23,487,806	3,983,583	150,849,541
Investment Tax Credit for Balance of Plant	2,720,154	7,605,019	6,912,534	1,201,793	-	18,439,500
Total Trimble County Unit 2 Expenditures, LG&E	$ 29,330,464	$ 63,729,115	$ 65,606,767	$ 30,218,167	$ 5,417,418	194,301,931
Total Investment Tax Credit, LG&E	$ 3,000,000	$ 9,559,367	$ 9,841,015	$ 1,349,618	$ -	$ 23,750,000
Kentucky Utilities Company						
Trimble County Unit 2 Air Quality Control Systems	$ 11,664,000	$ 55,544,636	$ 83,230,507	$ 28,692,590	$ 6,112,665	$ 185,244,398
Investment Tax Credit for Air Quality Control Systems	1,430,255	8,331,695	12,484,576	1,162,474	-	23,409,000
Balance of Trimble County 2 Capital Expenditures	86,198,288	216,142,644	196,461,502	100,132,224	16,982,642	615,917,300
Investment Tax Credit for Balance of Plant	10,569,745	32,421,397	29,469,225	5,380,633	-	77,841,000
Total Trimble County Unit 2 Expenditures, KU	$ 97,862,288	$ 271,687,280	$ 279,692,009	$ 128,824,814	$ 23,095,307	801,161,698
Total Investment Tax Credit, KU	$ 12,000,000	$ 40,753,092	$ 41,953,801	$ 6,543,107	$ -	$ 101,250,000
Total E.On US						
Trimble County Unit 2 Air Quality Control Systems	$ 14,400,000	$ 68,573,625	$ 102,753,713	$ 35,422,950	$ 7,546,500	$ 228,696,788
Investment Tax Credit for Air Quality Control Systems	1,710,101	10,286,043	15,413,057	1,310,299	-	28,719,500
Balance of Trimble County 2 Capital Expenditures	112,792,753	266,842,770	242,545,064	123,620,030	20,966,225	766,766,842
Investment Tax Credit for Balance of Plant	13,289,899	40,026,416	36,381,759	6,582,426	-	96,280,500
Total Trimble County Unit 2 Expenditures, E.On US	$ 127,192,753	$ 335,416,395	$ 345,298,777	$ 159,042,980	$ 28,512,725	995,463,629
Total Investment Tax Credit, E.On US	$ 15,000,000	$ 50,312,459	$ 51,794,816	$ 7,892,725	$ -	$ 125,000,000

Based upon the previous findings, we have determined KU's pro forma Kentucky jurisdictional rate base for rate-making purposes as of September 30, 2003 to be as follows:

Total Utility Plant in Service	$2,898,076,555
Add:	
Materials & Supplies	57,926,039
Prepayments	2,935,464
Emission Allowances	59,742
Cash Working Capital Allowance	49,853,452
Subtotal	$ 110,774,697
Deduct:	
Accumulated Depreciation	1,374,772,984
Customer Advances	1,455,980
Accumulated Deferred Income Taxes	244,469,347
SFAS 109 Accumulated Deferred Income Taxes	(17,891,956)
Investment Tax Credit (prior law)	5,453,260
Subtotal	$1,608,259,615
Pro Forma Electric Rate Base	$1,400,591,637

Reproduction Cost Rate Base

KU presented a total company reproduction cost rate base of $3,160,720,995, and a Kentucky jurisdictional reproduction cost rate base of $2,752,873,919.[1] The costs were determined principally by indexing the surviving plant and equity using the Handy-Whitman Index of Public Utility Construction Costs and the Consumer Price Index.[2] The Commission has given consideration to the proposed reproduction cost rate base, but finds that using KU's historic cost for rate base is appropriate and consistent with precedents for KU and other utilities in Kentucky.

[1] Rives Direct Testimony, Rives Exhibit 4.

[2] Rives Direct Testimony at 24.

Current Form approved December 21, 2006 in Case No. 2006-00206
ES FORM 2.00

KENTUCKY UTILITIES COMPANY
ENVIRONMENTAL SURCHARGE REPORT

Revenue Requirements of Environmental Compliance Costs
For the Expense Month of

Determination of Environmental Compliance Rate Base

	Enviromental Compliance Plan	
Eligible Pollution Control Plant		
Eligible Pollution CWIP Excluding AFUDC		
Subtotal		
Additions:		
Inventory - Limestone		
Less: Limestone Inventory in base rates		
Inventory - Emission Allowances per ES Form 2.31, 2.32 and 2.33		
Less: Allowance Inventory Baseline		
Net Emission Allowance Inventory		
Cash Working Capital Allowance		
Subtotal		
Deductions:		
Accumulated Depreciation on Eligible Pollution Control Plant		
Pollution Control Deferred Income Taxes		
Subtotal		
Environmental Compliance Rate Base		

Determination of Pollution Control Operating Expenses

	Enviromental Compliance Plan
Monthly Operations & Maintenance Expense	
Monthly Depreciation & Amortization Expense	
Monthly Taxes Other Than Income Taxes	
Monthly Insurance Expense	
Monthly Emission Allowance Expense from ES Form 2.31, 2.32 and 2.33	
Less Monthly Emission Allowance Expense in base rates (1/12 of $58,345.76)	
Net Recoverable Emission Allowance Expense	
Monthly Surcharge Consultant Fee	
Total Pollution Control Operations Expense	

Proceeds From By-Product and Allowance Sales

	Total Proceeds
Allowance Sales	
Scrubber By-Products Sales	
Total Proceeds from Sales	

True-up Adjustment: Over/Under Recovery of Monthly Surcharge Due to Timing Differences

A. MESF for two months prior to Expense Month	
B. Net Jurisdictional E(m) for two months prior to Expense Month	
C. Environmental Surcharge Revenue, current month (from ES Form 3.00)	
D. Retail E(m) recovered through base rates (Base Revenues, ES Form 3.00 times 0.3%)	
E. Over/(Under) Recovery due to Timing Differences ((D + C) - B)	
Over-recoveries will be deducted from the Jurisdictional E(m); under-recoveries will be added to the Jurisdictional E(m)	

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ES FORM 2.00

KENTUCKY UTILITIES COMPANY
ENVIRONMENTAL SURCHARGE REPORT

Revenue Requirements of Environmental Compliance Costs
For the Expense Month of

Determination of Environmental Compliance Rate Base

	Enviromental Compliance Plan	
Eligible Pollution Control Plant		
Eligible Pollution CWIP Excluding AFUDC		
Subtotal		
Additions:		
Inventory - Limestone		
Less: Limestone Inventory in base rates		
Inventory - Emission Allowances per ES Form 2.31, 2.32 and 2.33		
Less: Allowance Inventory Baseline		
Net Emission Allowance Inventory		
Cash Working Capital Allowance		
Subtotal		
Deductions:		
Accumulated Depreciation on Eligible Pollution Control Plant		
Pollution Control Deferred Income Taxes		
Pollution Control Deferred Investment Tax Credit		
Subtotal		
Environmental Compliance Rate Base		

Determination of Pollution Control Operating Expenses

	Enviromental Compliance Plan
Monthly Operations & Maintenance Expense	
Monthly Depreciation & Amortization Expense	
Monthly Taxes Other Than Income Taxes	
Monthly Insurance Expense	
Monthly Emission Allowance Expense from ES Form 2.31, 2.32 and 2.33	
Less Monthly Emission Allowance Expense in base rates (1/12 of $58,345.76)	
Net Recoverable Emission Allowance Expense	
Monthly Surcharge Consultant Fee	
Total Pollution Control Operations Expense	

Proceeds From By-Product and Allowance Sales

	Total Proceeds
Allowance Sales	
Scrubber By-Products Sales	
Total Proceeds from Sales	

True-up Adjustment: Over/Under Recovery of Monthly Surcharge Due to Timing Differences

A. MESF for two months prior to Expense Month	
B. Net Jurisdictional E(m) for two months prior to Expense Month	
C. Environmental Surcharge Revenue, current month (from ES Form 3.00)	
D. Retail E(m) recovered through base rates (Base Revenues, ES Form 3.00 times 0.3%)	
E. Over/(Under) Recovery due to Timing Differences ((D + C) - B)	
Over-recoveries will be deducted from the Jurisdictional E(m); under-recoveries will be added to the Jurisdictional E(m)	

Current Form approved December 21, 2006 in Case No. 2006-00206
ES FORM 2.10
Page x of y

KENTUCKY UTILITIES COMPANY
ENVIRONMENTAL SURCHARGE REPORT
Plant, CWIP & Depreciation Expense

For the Month Ended:

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
Description	Eligible Plant In Service	Eligible Accumulated Depreciation	CWIP Amount Excluding AFUDC	Eligible Net Plant In Service	Deferred Tax Balance as of	Monthly Depreciation Expense	Monthly Property Tax Expense
				(2)-(3)+(4)			
2001 Plan: Project 16 - KU Nox modifications Project 17 - KU Nox SCR's							
Subtotal Less Retirements and Replacement resulting from implementation of 2001 Plan							
Net Total - 2001 Plan:							
2003 Plan: Project 18 - Ghent Ash Pond Dike Elevation							
Subtotal Less Retirements and Replacement resulting from implementation of 2003 Plan							
Net Total - 2003 Plan:							
2005 Plan: Project 19 - Ash Handling at Ghent 1 and Ghent Station Project 20 - Ash Treatment Basin Expansion at E.W. Brown Station Project 21 - FGD's at all E.W. Brown Units and at Ghent 1, 3, and 4							
Subtotal Less Retirements and Replacement resulting from implementation of 2005 Plan							
Net Total - 2005 Plan:							
2006 Plan: Project 23 - TC2 AQCS Equipment Project 24 - Sorbent Injection Project 25 - Mercury Monitors Project 26 - Ghent 2 SCR Project 27 - E.W. Brown Electrostatic Precipitators							
Subtotal Less Retirements and Replacement resulting from implementation of 2006 Plan							
Net Total - 2006 Plan:							
Net Total - All Plans:							

Revised
ES FORM 2.10
Page x of y

KENTUCKY UTILITIES COMPANY
ENVIRONMENTAL SURCHARGE REPORT
Plant, CWIP & Depreciation Expense

For the Month Ended:

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
Description	Eligible Plant In Service	Eligible Accumulated Depreciation	CWIP Amount Excluding AFUDC	Eligible Net Plant In Service	Unamortized ITC as of mm/dd/yyyy	Deferred Tax Balance as of mm/dd/yyyy	Monthly Depreciation Expense	Monthly Property Tax Expense
				(2)-(3)+(4)				
2001 Plan:								
Project 16 - KU Nox modifications								
Project 17 - KU Nox SCR's								
Subtotal								
Less Retirements and Replacement resulting from implementation of 2001 Plan								
Net Total - 2001 Plan:								
2003 Plan:								
Project 18 - Ghent Ash Pond Dike Elevation								
Subtotal								
Less Retirements and Replacement resulting from implementation of 2003 Plan								
Net Total - 2003 Plan:								
2005 Plan:								
Project 19 - Ash Handling at Ghent 1 and Ghent Station								
Project 20 - Ash Treatment Basin Expansion at E.W. Brown Station								
Project 21 - FGD's at all E.W. Brown Units and at Ghent 1, 3, and 4								
Subtotal								
Less Retirements and Replacement resulting from implementation of 2005 Plan								
Net Total - 2005 Plan:								
2006 Plan:								
Project 23 - TC2 AQCS Equipment								
Project 24 - Sorbent Injection								
Project 25 - Mercury Monitors								
Project 26 - Ghent 2 SCR								
Project 27 - E.W. Brown Electrostatic Precipitators								
Subtotal								
Less Retirements and Replacement resulting from implementation of 2006 Plan								
Net Total - 2006 Plan:								
Net Total - All Plans:								

KENTUCKY UTILITIES

Capitalization at December 31, 2006

		Per Books 12-31-06 (1)	Capital Structure (2)	Undistributed Subsidiary Earnings (3)	Investment in EEI (Col 2 x Col 4 Line 5) (4)	Investments in OVEC and Other (Col 2 x Col 5 Line 5) (5)	Adjustments to Total Company Capitalization (7)	Adjusted Total Company Capitalization (8)
1.	Short Term Debt	$ 97,043,054	4.55%	$ -	$ (798,256)	$ (30,764)	$ (829,020)	$ 96,214,034
2.	Long Term Debt	842,384,680	39.50%	-	(6,929,914)	(267,075)	(7,196,989)	835,187,691
3.	Preferred Stock	-	0.00%	-	-	-	-	-
4.	Common Equity	1,193,198,003	55.95%	(16,248,287)	(9,815,917)	(378,301)	(26,442,505)	1,166,755,498
5.	Total Capitalization	$ 2,132,625,737	100.00%	$ (16,248,287)	$ (17,544,087)	$ (676,140)	$ (34,468,514)	$ 2,098,157,223

		Adjusted Total Company Capitalization (8)	Jurisdictional Rate Base Percentage (Exhibit KWB-5, Pg 3, Line 23) (9)	Kentucky Jurisdictional Capitalization (Col 8 x Col 9) (10)	Adjusted Capital Structure (11)	Annual Cost Rate (12)	Cost of Capital (Col 11 x Col 12) (13)
1.	Short Term Debt	$ 96,214,034	73.03%	$ 70,265,109	4.59%	5.250%	0.24%
2.	Long Term Debt	835,187,691	73.03%	609,937,571	39.81%	4.832%	1.92%
3.	Preferred Stock	-	73.03%	-	0.00%	0.000%	0.00%
4.	Common Equity	1,166,755,498	73.03%	852,081,541	55.60%	10.00% - 10.50% - 11.00%	5.56% - 5.84% - 6.12%
5.	Total Capitalization	$ 2,098,157,223		$ 1,532,284,221	100.00%		7.72% - 8.00% - 8.28%

KENTUCKY UTILITIES

Net Original Cost Kentucky Jurisdictional Rate Base
At December 31, 2006

Title of Account (1)	Kentucky Jurisdictional Rate Base at December 31, 2006 (2)	Kentucky Jurisdictional ECR Rate Base at December 31, 2006 (3)	Kentucky Jurisdictional ECR Roll-In Rate Base (4)	Kentucky Jurisdictional Base Rate Base at December 31, 2006 (5) (2 - 3 + 4)	Other Jurisdictional Rate Base at December 31, 2006 (6)	Total Company Rate Base at December 31, 2006 (7) (2 + 6)
1. Utility Plant at Original Cost	$ 3,636,980,697	$ 383,165,706	$ 16,028,082	$ 3,269,843,073	$ 530,997,430	$ 4,167,978,127
2. Deduct:						
3. Reserve for Depreciation	1,598,291,586	13,624,794	56,119	1,584,722,910	251,720,568	1,850,012,154
4. Net Utility Plant	2,038,689,111	369,540,912	15,971,964	1,685,120,163	279,276,862	2,317,965,973
5. Deduct:						
6. Customer Advances for Construction	1,958,015	-	-	1,958,015	14,851	1,972,866
7. Accumulated Deferred Income Taxes	265,376,423	26,076,747	70,326	239,370,003	39,033,869	304,410,292
8. Asset Retirement Obligation-Net Assets	4,514,843	-	-	4,514,843	713,938	5,228,781
9. Asset Retirement Obligation-Liabilities	(24,592,383)	-	-	(24,592,383)	(3,888,824)	(28,481,207)
10. Asset Retirement Obligation-Regulatory Assets	19,009,128	-	-	19,009,128	3,005,937	22,015,065
11. Asset Retirement Obligation-Regulatory Liabilities	(1,656,694)	-	-	(1,656,694)	(261,975)	(1,918,669)
12. Reclassification of Accumulated Depreciation associated		-	-			
with Cost of Removal for underlying ARO Assets	2,062,288	-	-	2,062,288	326,112	2,388,400
13. Investment Tax Credit (a)	11,108,450	1,220,651	-	9,887,799	1,915,326	13,023,776
14. Total Deductions	277,780,070	27,297,398	70,326	250,552,999	40,859,234	318,639,304
15. Net Plant Deductions	1,760,909,041	342,243,514	15,901,637	1,434,567,164	238,417,628	1,999,326,669
16. Add:						
17. Materials and Supplies (b)	82,710,972	-	-	82,710,972	12,824,899	95,535,871
18. Prepayments (b)(c)	1,684,590	-	-	1,684,590	234,840	1,919,430
19. Emission Allowances	1,442,446	1,378,801	-	63,645	228,092	1,670,538
20. Cash Working Capital (page 2)	72,088,950	158,928	-	71,930,022	7,917,882	80,006,832
21. Total Additions	157,926,958	1,537,730	-	156,389,228	21,205,713	179,132,671
22. Total Net Original Cost Rate Base	$ 1,918,835,999	$ 343,781,243	$ 15,901,637	$ 1,590,956,393	$ 259,623,341	$ 2,178,459,340
23. Percentage of KY Jurisdictional Base Rate Base to Total Company Rate Base				73.03%		

(a) Reflects investment tax credit treatment as proposed herein
(b) Average for 13 months.
(c) Includes prepayments for property insurance only.

KENTUCKY UTILITIES

Calculation of Cash Working Capital
At December 31, 2006

Title of Account (1)	Kentucky Jurisdictional Rate Base at December 31, 2006 (2)	Kentucky Jurisdictional ECR Rate Base at December 31, 2006 (3)	Kentucky Jurisdictional ECR Roll-In Rate Base (4)	Kentucky Jurisdictional Base Rate Base at December 31, 2006 (5) (2 - 3 + 4)	Other Jurisdictional Rate Base at December 31, 2006 (6)	Total Company Rate Base at December 31, 2006 (7) (2 + 6)
1. Operating and maintenance expense for the 12 months ended December 31, 2006	$ 734,520,303	$ 1,271,426	$ -	$ 733,248,877	$ 108,696,070	$ 843,216,373
2. Deduct:						
3. Electric Power Purchased	157,808,700	-	-	157,808,700	24,636,355	182,445,055
4. Total Deductions	$ 157,808,700	$ -	$ -	$ 157,808,700	$ 24,636,355	$ 182,445,055
5. Remainder (Line 1 - Line 5)	$ 576,711,603	$ 1,271,426	$ -	$ 575,440,178	$ 84,059,715	$ 660,771,318
6. Cash Working Capital	$ 72,088,950	$ 158,928	$ -	$ 71,930,022	$ 7,917,882	$ 80,006,832

Kentucky Jurisdictional (12 1/2% of Line 5)
Other Jurisdictional comprised of FERC, Tennessee, and Virginia Jurisdictional methodologies.

KENTUCKY UTILITIES

Net Original Cost Kentucky Jurisdictional Rate Base
At December 31, 2006

Title of Account (1)	Kentucky Jurisdictional ECR Rate Base at December 31, 2006 (2)	Other Jurisdictional ECR Rate Base at December 31, 2006 (3)	Total Company ECR Rate Base at December 31, 2006 (4)	Kentucky Jurisdictional ECR Roll-In Rate Base (5)
1. Utility Plant at Original Cost	$ 383,165,706	$ 60,590,468	$ 443,756,174	$ 16,028,082
2. Deduct:				
3. Reserve for Depreciation	13,624,794	2,154,506	15,779,300	56,119
4. Net Utility Plant	369,540,912	58,435,962	427,976,874	15,971,964
5. Deduct:				
6. Customer Advances for Construction	-	-	-	-
7. Accumulated Deferred Income Taxes	26,076,747	4,123,548	30,200,295	70,326
8. Asset Retirement Obligation-Net Assets	-	-	-	-
9. Asset Retirement Obligation-Liabilities	-	-	-	-
10. Asset Retirement Obligation-Regulatory Assets	-	-	-	-
11. Asset Retirement Obligation-Regulatory Liabilities	-	-	-	-
12. Reclassification of Accumulated Depreciation associated with Cost of Removal for underlying ARO Assets	-	-	-	-
13. Investment Tax Credit (a)	1,220,651	209,604	1,430,255	-
14. Total Deductions	27,297,398	4,333,152	31,630,550	70,326
15. Net Plant Deductions	342,243,514	54,102,810	396,346,324	15,901,637
16. Add:				
17. Materials and Supplies	-	-	-	-
18. Prepayments	-	-	-	-
19. Emission Allowances	1,378,801	218,032	1,596,833	-
20. Cash Working Capital	158,928	24,957	183,885	-
21. Total Additions	1,537,730	242,988	1,780,718	-
22. Total Net Original Cost Rate Base	$ 343,781,243	$ 54,345,799	$ 398,127,042	$ 15,901,637

(a) Reflects investment tax credit treatment as proposed herein

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MAY 04 2007

PUBLIC SERVICE
COMMISSION

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

RECEIVED

MAY 04 2007

PUBLIC SERVICE
COMMISSION

In the Matter of:

APPLICATION OF KENTUCKY	)	
UTILITIES COMPANY FOR AN ORDER	)	
AUTHORIZING INCLUSION OF	)	
INVESTMENT TAX CREDITS IN	)	CASE NO. 2007-00178
CALCULATION OF ENVIRONMENTAL	)	
SURCHARGE AND DECLARING	)	
APPROPRIATE RATEMAKING	)	
METHODS FOR BASE RATES	)	

DIRECT TESTIMONY OF
RONALD L. MILLER
DIRECTOR OF CORPORATE TAX
E.ON U.S. SERVICES INC.

Filed: May 4, 2007

Q. Please state your name, position and business address.

A. My name is Ronald L. Miller. I am the Director of Corporate Tax for E.ON U.S. Services Inc., which provides services to Louisville Gas and Electric Company ("LG&E") and Kentucky Utilities Company ("KU") (collectively, "the Companies"). My business address is 220 West Main Street, Louisville, Kentucky 40202. A complete statement of my education and work experience is attached to this testimony as Appendix A.

Q. Have you previously testified before this Commission?

A. While I have sponsored responses to data requests for the Companies in a number of proceedings, including the 2004 rate cases, I have not submitted written testimony or testified in a hearing.

Q. What are the purposes of your testimony?

A. The purposes of my testimony are: (1) to describe the investment tax credit at issue in this proceeding and to summarize the process by which KU obtained it; (2) to describe the tax accounting treatment of the credit; and (3) to state the consequences of not following the rate treatment for the tax credit required by federal law.

Q. Are you sponsoring all of the Exhibits to KU's Application in this proceeding?

A. Yes, I am sponsoring all of the Exhibits to the Application:

- Internal Revenue Service Notice 2006-24 (KU Application Exhibit 1)
- KU's U.S. Department of Energy Application (without attachments) (KU Application Exhibit 2)
- KU's U.S. Internal Revenue Service ("IRS") Application (without Exhibit 1 – U.S. Department of Energy Application) (KU Application Exhibit 3)

- IRS certification letter (KU Application Exhibit 4)
- IRS letter accepting KU's IRS Application (KU Application Exhibit 5)
- KU-IRS Closing Agreement (KU Application Exhibit 6)

Q. Please describe the investment tax credit KU has obtained.

A. The federal Energy Policy Act of 2005 created several investment tax credits designed to spur the development and construction of certain kinds of generation facilities. One such credit is the Qualifying Advanced Coal Project Credit (see 26 U.S.C. § 48A) ("'05 EPA ITC"), which allows the Secretary of the Treasury to grant up to $1.3 billion in tax credits to advanced coal projects, $800 million for integrated gasification combined-cycle projects and $500 million for projects using other advanced coal-based generation technologies. The Companies applied for and were allocated up to $125 million in tax credits for the design and construction of Trimble County Unit No. 2 ("TC2"), which qualifies as an "advanced coal-based generation technology" project.

Q. What criteria did Trimble County Unit No. 2 have to meet to qualify as an "advanced coal-based generation technology" project?

A. The Qualifying Advanced Coal Project Credit statute (26 U.S.C. § 48A) sets out two key categories of criteria for eligibility to receive an advanced coal-based generation technology credit: high-efficiency and low-emissions. Thus, a clean but inefficient unit would not qualify, nor would a highly efficient unit that fails to meet stringent environmental standards. Specifically, to qualify a project must: (1) have a "design net heat rate of 8530 Btu/kWh (40 percent efficiency)"; and (2) be designed to remove 99% of sulfur dioxide and 90% of mercury, and emit no more than 0.07 lbs of nitrous oxide and 0.015 lbs of particulate matter per MMBtu. (26 U.S.C. § 48A(f).) The qualifying advanced coal project also must meet these general criteria: have a nameplate rating of 400 Mw or greater, use at least 75% coal for fuel, have 50% or more electrical power output, and be located at one site.

Q. How did KU obtain the '05 EPA ITC?

A. On March 13, 2006, the U.S. Internal Revenue Service issued Internal Revenue Service Notice 2006-24 ("Notice"), which "establishe[d] the qualifying advanced coal project program under § 48A(d) of the Internal Revenue Code." Among other things, the Notice set out the procedures for applying for the '05 EPA ITC. (A copy of Internal Revenue Service Notice 2006-24 is attached to KU's Application as Exhibit 1.) On June 28, 2006, KU and LG&E jointly filed an application with the U.S. Department of Energy ("DoE") to obtain the credit. In their application, the Companies described in detail TC2's design, and particularly why it meets the requirements discussed above (among others). (A copy of the DoE application [1] is attached to KU's Application as Exhibit 2.) On September 27, 2006, the Companies submitted an application for the credit to the U.S. Internal Revenue Service ("IRS"), along with additional certification documents that, following the IRS's approval of the application, would allow the Companies to begin claiming the tax credits as qualified progress expenditures are made. (A copy of the IRS application (without its Exhibit 1 attachment)[2] is attached to KU's Application as Exhibit 3.) On October 27, 2006, the IRS notified the Companies that the TC2 project received DoE certification.

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[1] The attachments consist of 50 pounds of paper documents, a number of which are documents on file at the Commission or are technical drawings and specifications for the design and construction of Trimble County Unit No. 2. An index of the attachments is set forth at pages 6 through 8 of the DoE application.

[2] Exhibit 1 to the IRS Application is the DoE Application referenced in this filing as Exhibit 2.

(A copy of the IRS certification letter is attached to KU's Application as Exhibit 4.) On November 29, 2006, the IRS informed the Companies that it too had accepted the Project's application and had allocated a total advanced coal project credit of $125 million. (A copy of the decision is attached to KU's Application as Exhibit 5.) On March 22, 2007, the IRS executed a Closing Agreement required in connection with realizing the $125 million tax credit. (A copy of the Closing Agreement is attached to KU's Application as Exhibit 6.) The Companies received the Closing Agreement from the IRS on April 9, 2007.

Q. What additional steps are required in obtaining the credit?

A. The project must meet certain certification requirements within two years of being allocated the '05 EPA ITC. This "certification" is granted by the IRS and determines whether all applicable environmental permits have been obtained as well as whether a binding contract has been entered for the main steam turbine. KU has completed these two steps and has requested "certification" by the IRS.

According to the IRS, at this time, the request for "certification" of the TC2 generation facility (e.g., evidence that all permits have been obtained, major contracts completed, etc.) is under review and consideration at the Houston IRS Field Office for appropriate action. While this step must be completed within two years of being allocated the credit, it does not prohibit the Company from claiming qualified progress expenditures at this time. The approval of the certification application is not expected to be an issue because TC2 is already under construction.

Q. What expenditures are eligible for the credits?

A. The relevant part of the '05 EPA ITC statute provides that any property that is part of an advanced coal-based generation project is "eligible property," the basis of which is a qualified investment upon which a 15% credit may be claimed. (See 26 U.S.C. § 48A(a)(2), (b)(1) & (c)(3).) The statute further provides that the default time for claiming such credits is when the eligible property is placed in service for tax purposes; however, the law also makes provision for "qualified progress expenditures" that allow the credits to be claimed in the years that the Companies make expenditures for certain "eligible property." (See 26 U.S.C. § 48A(b)(1) & (3).) The Companies anticipate that nearly all of their expenditures will be "qualified progress expenditures," meaning that the Companies will be able to claim their 15% credit for the tax years in which they make the expenditures. The credit allocated to the Companies is limited to a total of $125 million.

The Companies currently believe they will be able to claim the full $125 million credit. As supplied to the IRS, below is what the Companies anticipate spending for the major components of building Trimble County Unit No 2:

Steam Generator	$108,800,000
Steam Turbine	47,000,000
Air Quality Control System Package	220,200,000
SCR	24,400,000
Ash Handling	18,400,000
Other Pollution Control Costs	42,000,000
Balance Of Project and Construction	579,700,000
Development Costs	15,500,000
Total Capital Project Budget	$1,056,000,000
Less IMEA/IMPA 25% ownership	(264,000,000)
Total Transmission	84,000,000
Capitalized Interest	112,000,000
Total Capital	$988,000,000

The Companies believe the $988 million of capital costs detailed above should meet the criteria of "qualified investment." Fifteen percent of $988 million is approximately $148 million; therefore, the Companies will in all likelihood be able to take full advantage of their $125 million allocation of tax credits.

Q. How will KU account for its portion of the '05 EPA ITC?

A. KU will record (separately or as part of other periodic tax entries) on its financial statements: (1) a debit in FERC Account No. 236 - Taxes Accrued and a credit in FERC Account No. 409 - Federal Income Tax Expense; and (2) a debit in FERC Account No. 411.4 - Investment Tax Credit Adjustments and a credit in FERC Account No. 255 - Accumulated Deferred Investment Tax Credit. KU recorded entries in December 2006 with respect to the progress expenditure credits claimed in that year, and will continue to record entries through 2010, (projected in service date) for a total of $101,250,000 based on current estimates. (Because Illinois Municipal Electric Agency and Indiana Municipal Power Agency will not receive any portion of the '05 EPA ITC, KU and LG&E will share the credit in proportion to their respective ownership interests in TC2. Thus, KU's pro rata share of the '05 EPA ITC will be 81 percent of $125,000,000, which is $101,250,000.)

KU will also record on its balance sheet a debit to FERC Account No. 255 - Accumulated Deferred Investment Tax Credit, and a corresponding credit on its income statement to FERC Account No. 420 - Amortization of Investment Tax Credit. These amortization entries will begin when the unit goes into service for tax purposes (projected to be 2010) and will continue over the regulatory life of the unit.

The air quality control system and balance of the plant are currently estimated to have regulatory lives of 28.8 and 41.5 years, respectively.

Q. Why will KU normalize its '05 EPA ITC as described above?

A. KU has a long-standing election under federal normalization rules, which is irrevocable, that requires KU to normalize the credit in the manner I have described above. KU made the election pursuant to former 26 U.S.C. § 46(f) in 1972 and has since that time consistently normalized all investment tax credits pursuant to the method it elected. Although 26 U.S.C. § 46(f) has since been repealed, it continues to apply to new investment tax credits such as the '05 EPA ITC through current 26 U.S.C. § 50(d)(2)[3]. Moreover, the IRS also explicitly stated in its March 13, 2006 Internal Revenue Service Notice 2006-24, "The at-risk rules in § 49 and the recapture and other special rules in § 50 apply to the qualifying advanced coal project credit." Thus, 26 U.S.C. § 50(d) applies to this credit, and KU is required to continue to normalize such credits in its traditional fashion.

Q. How long has KU followed this method of normalization?

A. Since 1972, KU has consistently followed this method of normalization when accounting for the investment tax credit and, as explained in Mr. Blake's testimony, in each of its base rate cases.

In 2006, KU amortized $1,082,000 to the below-the-line FERC Account No. 420 for prior Investment Tax Credit amounts. On December 31, 2006, KU had on its balance sheet (excluding Investment Tax Credit for TC2 of $12 million) $1,024,000

[3] 26 U.S.C. § 50(d) states: "Certain Rules Made Applicable—For purposes of this subpart, rules similar to the rules of the following provisions (as in effect of the day before the date of the enactment of the Revenue Reconciliation Act of 1990) shall apply: (2) Section 46(f) (relating to limitation in case of certain regulated companies)."

left to amortize. Based on current regulatory lives the amortization on these Investment Tax Credit amounts will end in 2009.

Q. If the Commission determined not to allow KU to normalize the '05 EPA ITC according to KU's previously elected method, what would be the consequence?

A. We believe the Internal Revenue Code ("IRC") on this issue is clear in that if KU does not normalize the credit in the manner KU elected in 1972, KU would lose the ability to claim the credit. If at any future time the Commission determines not to allow KU to continue to normalize the credit, again KU would lose the ability to claim any more of the credit, and the part KU had claimed would be subject to recapture. (See former 26 U.S.C. § 46(f)(1).) Such an event would also require "backing out" relevant accounting entries and could result in KU having to pay generally applicable tax penalties and interest on the recaptured amount.

Q. What is the impact of the '05 EPA ITC on KU's depreciable tax basis of the property?

A. IRC Section 50(c) requires the tax basis of the property to be reduced by the amount of the credit. Loss of depreciable tax basis will result in unfavorable permanent book versus tax differences over the life of the plant equal to the amount of the credit times the applicable tax rate, or approximately $35,437,500 ($101,250,000 X 35%). The resulting periodic incremental tax expense will begin at the time the unit is placed in service and will continue over the regulatory life of the unit. Additionally, other temporary book/tax differences will result from accelerated depreciation and other book versus tax depreciation/amortization methods. (See Exhibit KWB-1 to Kent W. Blake's testimony.)

Q. **Is KU guaranteed to receive the full amount of the '05 EPA ITC?**

A. No. The Company has signed a closing agreement with the Internal Revenue Service outlining various criteria required to receive the tax credit including "certification" by the IRS of the '05 EPA ITC project within two years, completion of the facility within five years of certification, and meeting fuel specifications. A proportionate reduction of the credit is also required if the gross TC2 nameplate generation of at least 833.6 megawatts is not met.

In addition to the KU-IRS Closing Agreement criteria, credit is potentially forfeited to the extent that tax exempt financing is obtained for the project.[4] For example, if $10,000,000 of tax exempt bond financing is obtained, KU's basis for purposes of computing the '05 EPA ITC is reduced by $10,000,000, resulting in the potential loss of $1,500,000 of credit. To the extent that tax exempt financing is available on TC2, the Company will compare the financing benefits with the benefits from the tax credit and determine the best decision for KU. Criteria for this decision would include a comparison of the present value of each benefit as well as the ability to benefit from both. Based on present cost estimates of TC2, it is possible to obtain tax exempt financing on a portion of TC2 and still realize the maximum advanced coal credit.

Q. **Does this conclude your testimony?**

A. Yes, it does.

[4] 26 U.S.C. § 48A(b)(2) states, "Rules similar to section 48(a)(4) [26 U.S.C. § 48(a)(4)] shall apply for purposes of this section." In turn, 26 U.S.C. § 48(a)(4) requires the reduction in credit-eligible basis for tax-exempt-financed amounts of advanced coal project credit projects such as TC2.

VERIFICATION

COMMONWEALTH OF KENTUCKY)
) SS:
COUNTY OF JEFFERSON)

The undersigned, **Ronald L. Miller**, being duly sworn, deposes and says he is Director of Corporate Tax 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.

RONALD L. MILLER

Subscribed and sworn to before me, a Notary Public in and before said County and State, this 4th day of May, 2007.

Notary Public (SEAL)

My Commission Expires:

November 9, 2010

APPENDIX A

Ronald L. Miller

Director, Corporate Tax and Payroll
E.ON U.S. Services Inc.
220 West Main Street
P. O. Box 32010
Louisville, Kentucky 40202
(502) 627-2687

Education

Eastern Kentucky University, B.B.A., major in Accounting, 1979
Certified Public Accountant, Kentucky, 1981
University of Louisville – The Effective Executive, 1996
Multiple Tax Executives Institute & other Tax/Accounting Educational Programs

Positions Held

E.ON US Services Inc. (LG&E Energy Corp.), Louisville, Kentucky
2001 (Jun) – Present – Director, Corporate Tax and Payroll
1998 (Jun) – 2001 (Jun) – Director, Corporate Accounting and Tax
1994 (Jul) – 1998 (Jun) – Director, Corporate Tax
1994 (Jan) – 1994 (Jul) – Corporate Tax Administrator
1992 (Feb) – 1993 (Dec) – Corporate Tax Coordinator

National City Bank, Louisville, Kentucky
1984 – 1992 – Vice President, Corporate Treasury Officer and Manager-Tax and General Accounting

Ernst and Young CPA's (f.k.a. Ernst and Whinney, CPA's)
1983 – 1984 – Audit Supervisor
1981 – 1983 – Audit Senior
1979 – 1981 – Audit Staff